DISTRIBUTED POWER GENERATION USING BIOGAS FUELLED MICROTURBINES

ETSU Contract B/U1/00670/00/REP
DTI/PubURN 02/1345

Contractor
Advantica

Prepared by
Kevin Pointon and Mike Langan

The work described in this report was carried out under contract as part of the New and Renewable Energy Programme, managed by ETSU on behalf of the Department of Trade and Industry. The views and judgments expressed in this report are those of the contractor and do not necessarily reflect those of ETSU or the Department of Trade and Industry.

First Published 2002

Executive Summary

Background

Biogas, from anaerobic digestion (AD) contains a mixture of methane and carbon dioxide, with a calorific value (CV) between 50% and 60% of that of natural gas. According to the UK Government's renewable energy strategy, there is considerable potential for electricity generation from biomass, and the European Union Renewable Energy Campaign for Take-off sets a target of 1GW of biogas fuelled installations throughout Europe by 2003.

The use of AD to generate biogas is a mature technology, however, despite government initiatives to promote its widespread use, biogas generation is limited to the wastewater treatment industry and to a few small farm based projects. One of the limitations is the availability and reliability of small-scale power generation technologies. The development of the biogas compatible microturbine could improve the reliability and performance of the power generation side of the plant. The establishment of a link between a well-characterised biogas demonstration with a microturbine with proven operation on natural gas is a significant extension to existing technology.

Objectives

There were three main objectives of this research programme

- to analyse the market for small scale biogas fuelled distributed generation technologies;
- to demonstrate the concept of a biogas fuelled microturbine based cogeneration system using a Capstone microturbine coupled to an anaerobic digestor facility
- to conduct a techno-economic assessment of the concept.

Results

Technology review and markets

A large market for distributed generation (DG) technologies is likely, the size being dependent on a complex mix of political economic and technological factors. By 2020, DG may account for 24GW of generating capacity in the UK. Biogas applications are likely to account for about 5% of this, or about 1% of total generating capacity. The integrated waste to energy concept can be cost effective. Applications where there is a waste management issue and large energy loads will receive the greatest benefits from this system. A number of current and emerging technologies would normally be fuelled with natural gas , but can also accept lower CV fuels. In particular steam engines, internal combustion engines, microturbines and Stirling engines accept biogas well. Fuel cells require more stringent purification of the fuel, which adds further expense to the system.
The benefits offered by a microturbine arise from its mode of operation. The fixed output, part-load efficiency and low maintenance are the key benefits which improve operational effectiveness. However, reduced electrical efficiency over piston engines may hinder market penetration.

Experimental trials
Trials have been undertaken, linking two types of anaerobic digester to a Capstone microturbine. The digesters were a continuous system based at the DeMontfort University test facility and a batch digester constructed on the Wirral. A range of feedstocks was used in the trial and the gas output analysed. Feedstocks included pig and cow slurries, vegetable waste and municipal solid waste. Performance and reliability of the turbine and the ancilliary equipment were assessed during the trial.

Output from a continuous feed digester was consistent as expected and generated a biogas containing 60% to 65% methane. The output from the batch digester was variable. Gases from the different batches were blended to provide a fuel with methane concentration between 50% and 70%. The microturbine worked well on the range of biogas fuels supplied. There is no evidence that the use of biogas affects the reliability of the turbine, however there was one failure of a component on the electrical side which was probably due to the use of a pre-production system.

Techno- Economic assessment
Driven largely by environmental factors, the development of the market for anaerobic digestion (AD) is expected. The attractiveness of many AD projects will depend on a complex economic case including capital costs, electricity savings and the sale of process by-products. Environmental incentives will be needed to stimulate a large take-up.
Payback periods will fall as waste management costs increase driven mainly by the increase in landfill tax. If processing cycles can be minimized, and optimal use is made of process byproducts, payback periods of less than 2 years are realistic.

Conclusions

The experience from the trial indicate that the microturbine will find application on biogas installations which will benefit from its fixed output, high part load efficiency and reliability. The only drawback is the efficiency, which is lower than that of the traditional technologies. When the waste management and energy efficiency elements are linked, the economic performance makes the concept attractive under current market conditions.

Recommendations

There is a requirement for further work to understand the outputs from different feedstocks under a range of process conditions; to develop the microbiology aspect of the process; to optimise the operation of the overall system and to understand the uses and values of the byproducts from the system. Once these elements are better understood the market analysis can be completed and the scale of the plant optimised. The technology should then be implemented in full scale field trial demonstrations.

Contents

	Page
1. Introduction	1
1.1 Background	1
1.2 Objectives	1
1.3 Methodology	2
1.4 Scope and Definitions	2
2. Technology Review	4
2.1 Biogas Technology	4
2.1.1 Landfills	4
2.1.2 Anaerobic Digesters	5
2.2 Biogas Characteristics	6
2.3 Generation Technologies	7
2.3.1 Conventional Technologies	7
2.3.2 Fuel Cells	8
2.3.3 Gas Turbines	13
2.3.4 Stirling Engines	16
2.3.5 Hybrid Systems	18
2.4 Biogas Fuelling Issues	19
2.5 Generation Technology Comparison	21
3. Markets	25
3.1 Applications for Biogas-Fuelled Distributed Generation	25
3.1.1 Power-Only Distributed Generation	26
3.1.2 Combined Heat and Power Distributed Generation	26
3.1.3 Operating Regimes	27
3.1.4 Generating Plant Scale	28
3.2 Market Drivers/Barriers	29
3.2.1 Distributed Generation as a Whole	30
3.2.2 Biogas-Fuelled Distributed Generation	38
3.3 Market sizes	43
3.3.1 Distributed Generation	43
3.3.2 Biogas-Fuelled Distributed Generation Accessible Market	46
3.3.3 Outlook for Biogas-Fuelled Microturbines	48
4. Demonstration Trial	50
4.1 Introduction	50
4.2 Installation and Monitoring	51
4.2.1 DeMontfort University Installation	52
4.2.2 AMEC IRW-EFR Installation	53
4.3 Trial Results	56
4.3.2 DeMontfort University Trial	56
4.3.2 AMEC IRW-EFR Trial	61

5. Techno-Economic Assessment 67

6. Conclusions 68

7. Recommendations 70

8. Acknowledgements 70

9. Information sources 71

1. Introduction

1.1 Background

Biogas, produced as the final product of the anaerobic digestion (AD) of organic materials (biomass) by certain microorganisms, has long been known to hold potential as a fuel, the first purpose-built AD plants appearing in the 19th century. In modern times, bioenergy is used all over the world, either by direct fuelling of boilers, cookers, etc, or by generation of biogas in purpose-built digesters or landfill sites. However, the contribution to the energy economies of most industrialised nations is minimal[1,2,3] – but is generally increasing slowly in line with generally increasing renewable energy use.

At the same time that the market for primary energy sources is shifting, so is the market for electricity generators. At present, the bulk of the world's electricity is generated in central power stations. This approach, one of 'economy of size', generates power in large, efficient power stations and delivers it to load centres via an extensive network of wires conducting synchronised alternating current. An alternative approach, that of distributed generation (DG), can be described as 'economy of mass production'; power is generated by many more smaller plant located near to load centres. This approach makes relatively little contribution to the world's electricity production, but is gathering momentum.

Of the factors driving change in these markets, environmental issues dominate and are largely common to both markets. This leads to a clear synergy between biogas and certain DG technologies – fuelling DG with biogas effectively reduces waste and displaces fossil fuel from the power generation economy, contributing to national targets for greenhouse gas emission.

A number of technologies will be available to compete in the biogas-fuelled distributed generation (BDG) market. These are small-scale power generation technologies that would normally be fuelled with natural gas, but which are capable of handling lower quality fuels. In particular, microturbines are attractive for a number of reasons including low emissions, compact size and potential low cost.

A paper study has been carried out by Advantica to investigate the issues surrounding the technology involved in BDG and the characteristics of the target market. This study forms part of the DTI-sponsored project 'Distributed Power Generation Using Biogas Fuelled Microturbines' and is described in this report.

1.2 Objectives

The prospects for biogas-fuelled microturbines will be a function of the development of the market for BDG combined with the ability of microturbines to compete in these markets by offering the required characteristics at a competitive price. The prospects for

BDG will also be influenced by the development of the wider market for DG. This study aimed to examine these issues in order to provide a basis for the realisation of commercial opportunities in this area.

Specific objectives were:

- review the relevant technologies in order to establish
  - the current technical and commercial status of the technologies
  - the issues surrounding their participation in biogas-fuelled power generation systems
  - the relative merits of microturbine-based systems
- assess the likely development of the market based on
  - what is known about the market for DG as a whole
  - the factors driving or retarding BDG

1.3 Methodology

The resources allocated for this exercise precluded carrying out a detailed independent market analysis. Instead the task was treated largely as a literature review. Much information is available in the literature concerning DG and biogas. Advocacy groups and trade associations, electricity utilities, fuel producers, and government agencies are all interested parties and freely publish material (particularly in the US) in the literature, at conferences and on the Internet. These sources, together with consultant's reports of market studies where available, were used as the primary font of information for this exercise.

1.4 Scope

The UK was the primary geographical area of interest, but the European Union and the US represent large power generation markets and were considered too. Thus, developing and transition countries were ignored, the study being one of BDG in OECD-type countries, where successful technology will be expected to offer economic/environmental benefits over a co-existing, well-developed central power generation system.

The period to 2020 was considered an appropriate timescale. This is because most information in the literature pertains to this period. The market beyond this timescale was considered too uncertain to yield worthwhile comment.

DG is a complex market with broad scope regarding technology, application and power range. Even the definition of DG varies widely between sources. For the purposes of this study, the widest definition (i.e. any power generation that that is not *central*) was narrowed to exclude generators with a capacity greater than 50MW, but still encompasses both CHP and power-only generation and includes renewable generation technologies. At the same time, since this exercise was essentially a literature survey, references are frequently discussed accepting whatever definitions of DG individual authors have applied, definitions that unfortunately have frequently not been stated explicitly.

This report is concerned with power generation from biogas. Biogas is taken to mean strictly the gaseous product of anaerobic digestion of organic material. The gas obtained by gasification of biomass, e.g. by pyrolysis, can also be used for power generation. But this gas is quite different, resembling synthesis gas rather than biogas[161], and is outside the scope of this report.

2. Technology Review

Fundamental to the development of a large market for BDG is the technology for both biogas production and small-scale electricity generation. This section examines the operating principles, characteristics, technological status and commercial status of these technologies.

2.1 Biogas technology

2.1.1 Landfills

The landfill represents a significant opportunity for biogas technology. In landfill sites, large quantities of municipal solid waste (MSW) are deposited and covered over with soil. Biogas is generated as the mass of MSW ages and is broken down by the process of anaerobic digestion (AD). Thus, biogas from landfills is essentially a by-product of an otherwise necessary waste disposal activity.

Control of gas emissions from landfills has long been recognised as necessary on health and safety grounds; over 400 control systems are operating in the US alone[42]. Recognised hazards include toxicity, fire and explosion[167]. In an environmental context, methane has a global warming potential some 23 times as great as carbon dioxide[158], a fact that has prompted concern over emissions from landfills. Whilst flaring of landfill gas converts all of the methane to carbon dioxide, the opportunity to displace carbon dioxide normally emitted from burning fossil fuels is lost if the energy is wasted. Consequently there is increasing interest in utilising the energy contained in this gas either by direct heating or for power generation.

Gas is typically collected from mature landfills using a series of strategically placed wells, shown in Figure 1. Insertion of perforated pipes surrounded by large-particle gravel allows collection of the gas without clogging of the pipes with stray MSW. A further means of recovering landfill gas is by horizontal underground trenches allowing additional layers to be added to the site. The piping system may be kept under slight negative pressure, facilitating migration of the gas to the wells. A variety of low-level contaminants can be present in landfill gas as a consequence of the variability of waste materials that can be deposited. Species such as siloxanes can be problematic at very low levels. Gas clean-up measures must be incorporated into the system design to ensure reliable operation of power generation equipment. This increases both capital and operational costs.

Landfill development and landfill gas collection is relatively mature technology. This is reflected in the UK industry structure, which sees a number of key players, none with a large market share[16].

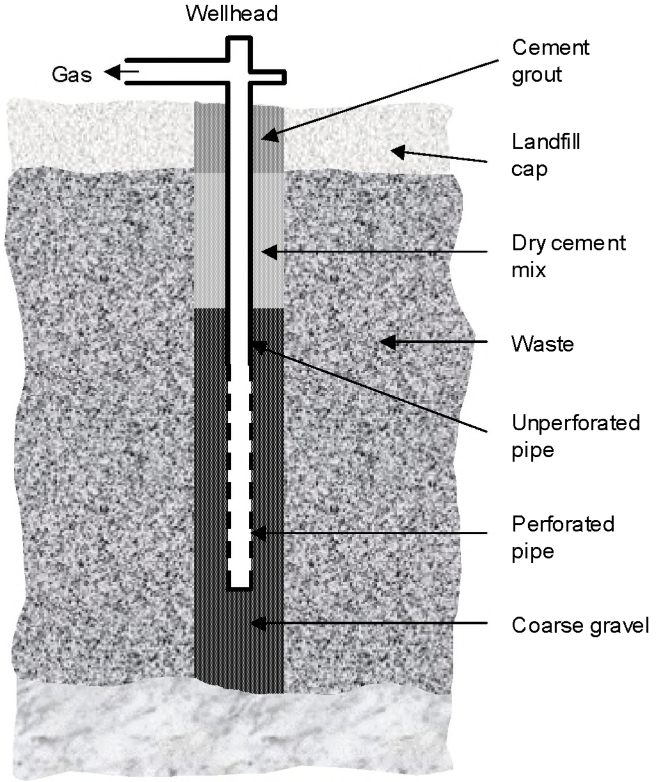


Figure 1. Principle of a Landfill Well

2.1.2 Anaerobic Digesters

A second biogas technology is the purpose-built anaerobic digester, capable of producing biogas from a wide range of waste material. The principle is shown in Figure 2. A biomass feedstock (usually organic waste) is fed to the digester where it remains for a number of days or weeks during which time it is broken down by anaerobic bacteria to produce biogas, which can be used to provide energy, a liquor which can be used as a fertiliser, and a solid residue, which can be used as a soil conditioner. Thus, the anaerobic digester converts waste material into several valuable products. In addition AD processes can be used to treat wastewater.

A good general review of this technology can be found in reference 115. Anaerobic digesters are warmed, sealed airless containers, which provide the correct conditions for anaerobic bacteria to break down organic matter. These take advantage of two AD processes: mesophilic digestion, working at 30-35°C with a feedstock retention time of 15-30 days, and thermophilic digestion, requiring 55°C and a feedstock retention time of

12-14 days. The latter process offers the best methane production rate and lower pathogen problems, but requires more expensive technology and greater energy input. The majority of European plants operate at mesophilic temperature[168].

Digesters can also be classified according to the reactor type[127]. In batch systems, material is digested in lots, often with several vessels in parallel with a staggered start-up to compensate for variation in output. In accumulation continuous flow systems, an essentially batch reactor serves as a manure pit and has material added and removed as needed. However, the most common reactor type is the continuous stirred tank reactor[168]. Material is added regularly and digested material collected via an overflow.

Anaerobic digesters are a relatively mature technology, having been developed for a number of years and with a great many systems in service at both large and small scales[eg 125, 126]. Commercially, they are available from a number of companies. In the UK, these include Greenfinch Ltd, Milbury Systems Ltd and Organic Power Ltd. Costs are around £100-£300k for a 300m^3 system[154]. As the feedstock used in digesters is more controlled, the number of contaminants can be reduced. Gas clean-up equipment can be specified to remove contaminants from specific feedstocks.

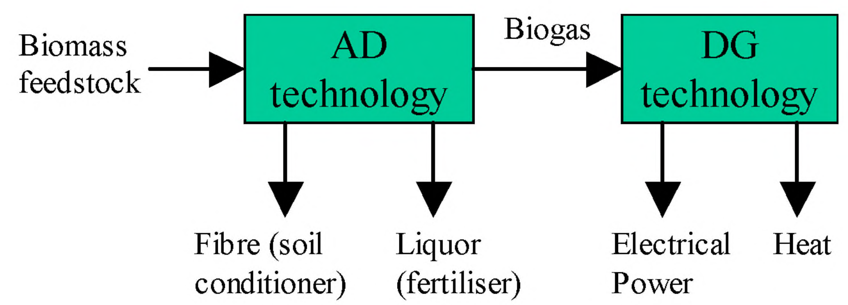


Figure 2. Principle of Biogas-Fuelled Distributed Generation

2.2 Biogas characteristics

The technological demands on the electrical generator for integration with a biogas source, such as an anaerobic digester or landfill site well, are largely dictated by the composition of the biogas. Just as the composition of natural gas does not have a single defined value, but is rather a function of geographical source, biogas is also of variable composition, which depends on a number of factors particularly the management of the process and the nature of the feedstock material[13]. Therefore, in order to be generally applicable, the power generation technology must be capable of coping with the full range of biogas compositions likely to be encountered. Literature information on this range is given in Table 1.

Table 1. Biogas Compositional Range

		Refs.	Composition
Fuels	Methane (%)	13, 14	50-80[b]
	Hydrogen (%)	15	1-2
Diluents	Carbon dioxide (%)	13, 14	20-50
	Nitrogen (%)	15, 161	0-10
	Oxygen (%)	161	0-2
Contaminants	Hydrogen sulphide[a] (%)	5, 116	0.01-2
	Ammonia (ppm)	7, 118	2.6-600

a) Trace quantities of a number of organo-sulphur compounds are also possible[7]
b) Rather lower figures have been reported from some landfill sites, but figures can be distorted by air ingress[166].

Table 1 shows that biogas is typically characterised by a low calorific value (CV), containing as it does significant quantities of diluents, which add no energy value. Typical methane concentrations of 50-80% translate into combustion enthalpies of 18-29MJ/m^3 (c.f. natural gas, typically around 38MJ/m^3). The issue is then whether a given generation technology can utilise such a gas, and if it can, how comparable its performance is to its conventionally fuelled variant.

A significant subtlety is that unlike natural gas, which is of consistent quality at the point of supply, variation of biogas quality with time is likely. This will place further demands on the power generation technology, which must be capable of handling transient changes in gas quality.

2.3 Small-Scale Generation Technologies

A number of power generation technologies are potentially available for biogas-fuelled applications. These are generally small-scale power generation technologies that would normally be fuelled with natural gas, but which are capable of handling lower quality fuels. This section reviews the operating principles, characteristics of and development/commercialisation status of the relevant technologies. For more detailed information on the status of some of these technologies, the reader is directed to reference 16.

2.3.1 Conventional Technologies

The two main categories of internal combustion engine (ICE), otherwise known as the reciprocating engine, are spark ignition and compression ignition. The ICE can also have a 2 or 4 stroke cycle. All systems have a crankshaft linked to a piston that moves within a cylinder. Biogas is usually utilised in a 4-stroke spark ignition engine.

In the 4-stroke spark ignition engine, the fuel is either mixed with the air or injected into the cylinder during the intake cycle. The piston then compresses the air/fuel mixture during the compression cycle. The fuel air mixture is ignited by a spark from a spark plug near the end of the compression cycle and combusts. Combustion causes the pressure and temperature of the mixture to increase, causing the piston to move and drive the crankshaft. As the crankshaft continues to rotate, the piston moves up in the cylinder forcing the products of combustion into the exhaust ready to start the cycle again. Combustion is intermittent and peak combustion temperatures approaching 1800°C are possible. The high peak combustion temperatures allow the formation of NO_x in the combustion products. Exhaust clean-up processes are used to reduce emissions.

The ICE is a highly developed technology. High volume production for the automotive industry has led to a reduction in costs. The technology has historically been the natural choice for small-scale power generation since it was the only cheap, well-known contender. ICEs have also been applied in cogeneration applications. In this mode, ICEs have two potential heat sources as heat can be recovered from the cooling jacket or exhaust gas stream or both. The use of ICEs in biogas applications has been known for many years and a large number of projects are operating[eg 150-152].

Biogas and landfill gas systems are available form several manufacturers; two of the major suppliers in the UK are Waukesha and Jenbacher. Engines are available in the size range from 95kW$_e$ to 2500kW$_e$ operating on fuels down to 15.7MJ/m^3 depending on engine type, although the majority of systems installed in the UK are towards the larger end of the size range. In the US, major suppliers include Caterpillar and MAN. 55kW$_e$-3.2kW$_e$ systems are available.

A second conventional power generation technology is the steam turbine. The steam turbine utilises an external combustion system to generate high temperature flue gas. Heat exchange to a boiler produces high-pressure steam, which is used to generate power in a Rankine cycle. The steam is allowed to expand isentropically through a turbine, condensed and then pumped back to the boiler. The shaft power from the turbine can be used to generate electricity.

As the combustion system is external, most fuel sources can be utilised, including solid biomass such as wood. Steam turbine technology is not in common use for small-scale power generation due to considerations such as poor economics and low efficiency. Many larger scale plants exist, including biomass-fuelled units.

2.3.2 Fuel Cells

A fuel cell is similar to a battery in that it is an energy conversion device that converts chemical energy into electrical energy. However, unlike a battery, the chemical compounds which react to release their chemical energy are not stored within the device or comprise any part its structure, but are continuously supplied in the form of a fuel and oxidant (usually air), reaction products being continually removed. The significance of these facts is that a fuel cell does not "run down" in the same way that a battery does, but is capable of producing electrical power for as long as fuel and air continue to be supplied.

The principle of operation of a proton exchange membrane (PEM) fuel cell running on hydrogen is shown in Figure 3. The fuel cell consists of two porous electrodes (the anode and the cathode) separated by a denser ion-conducting region known as the electrolyte. When there is no external circuit connected, no net chemical reactions occur. When an external circuit is made, the fuel cell produces current as follows.

- Hydrogen molecules are supplied to the anode and diffuse through it to the interface with the electrolyte where, encouraged by a catalyst, they split into protons and electrons.
- The electrons and the protons pass to the cathode by different paths, the protons through the electrolyte by virtue of its proton conducting ability and the electrons via an external electrical circuit where they do useful work (power generation).
- At the cathode/electrolyte interface the electrons and protons, again encouraged by a catalyst, combine with oxygen molecules, which have been fed to the cathode and have diffused through it.
- The resulting molecules of water diffuse back through the cathode to be carried away in the air stream.

The net chemical change is identical to that which would have occurred if the hydrogen had been combusted, i.e. hydrogen + oxygen $\rightarrow$ water, but the hydrogen and oxygen have never actually mixed.

The issue of the application of fuel cells to biogas is complicated by the fact that there are a number of distinct fuel cell types, each with different characteristics and at differing stages of development and commercialisation. The differences between the fuel cell types stem largely from the choice of electrolyte material and the temperature at which this is both stable and ion conducting. This results in differences in the nature of the ion conducted through the electrolyte, but they all work on the same basic principle of electrochemistry, i.e. oxidation of fuel and reduction of oxidant at different locations. In order of operating temperature, the main fuel cell types and their characteristics are listed in Table 2. The strongest contenders for stationary power are described below.

- *Proton Exchange Membrane Fuel Cell (PEMFC)*
  Because of their low temperature operation combined with operation on ambient air PEMFCs currently match the requirements for transportation use most closely. However, is important to realise that stationary power generation and vehicle propulsion have some requirements in common, low cost being the most notable. Cost targets for transportation use are much lower than for stationary power

generation. Thus, progress toward minimum costs for transportation is increasing the attractiveness of PEMFCs for stationary power.

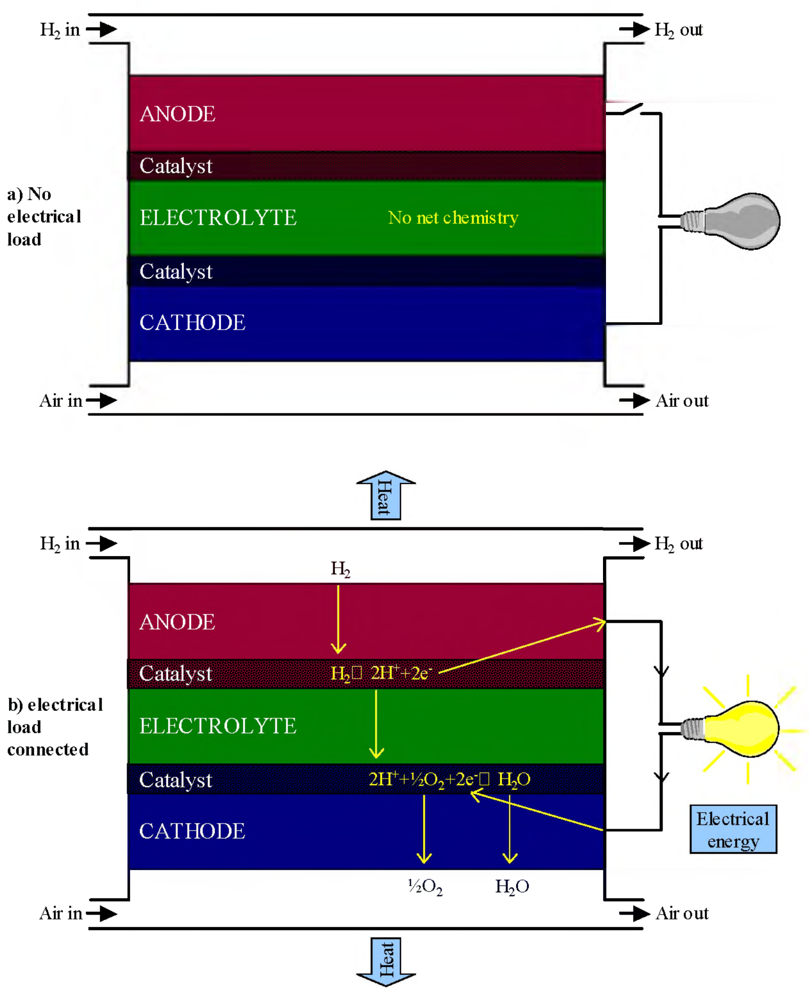


Figure 3. Operating Principle of an Acid Fuel Cell

Development programs are underway for small-scale systems of 1-10kW and 50-250kW stationary PEMFC power generators. Market leaders, Ballard, are currently at the field trial stage of development. To date they have shipped a total of five 250kW generators to locations in the US, Europe and Japan. The fifth unit was shipped in 2001 to a sewage treatment plant in Japan, the World's first example of a PEMFC running on biogas[20]. In addition, they plan on demonstrating 10kW and 60kW prototypes. Their timetable calls for commercialisation of stationary power plant by 2003[21].

- *Phosphoric Acid Fuel Cell (PAFC)*
  The most commercially developed fuel cell type; more than two hundred 200kW cogeneration units have been delivered[22] by ONSI/International Fuel Cells Inc (IFC). These generators have been shown to be reliable, but are too expensive to be competitive with conventional technology and have therefore achieved negligible market penetration.

  Deliveries for use on Biogas have been made to at least seven sites in the US, Europe and Japan, including a facility at the Yonkers Joint Wastewater Treatment Plant, New York[7], the Sludge Treatment Centre of Yokohama City, Japan[8] and the Groton landfill site, Connecticut[6].

  IFC's development plan centres on cost reduction. However, given the relatively late stage of development of this technology, it seems unlikely that the necessary dramatic price slash will be achieved for many years.

- *Molten Carbonate Fuel Cell (MCFC)*
  The first of the two fuel cell types regarded as "high temperature" fuel cells. A major advantage of MCFCs is that waste heat is at a temperature that is more suitable for combined heat and power applications. Alternatively, waste heat can be used to raise steam to generate further electricity by more conventional means in order to increase the already inherently higher efficiency still further. Furthermore, the higher temperature also means that simpler, more efficient fuel cell generators become possible when natural gas is used as the fuel (so-called internally reforming MCFCs).

  MCFCs are at the demonstration stage of development. Recent field trials by leading developers include two 250kW units demonstrated by FuelCell Energy (FCE) in the US[23] and by MTU-Friedrichshafen in Germany[24], both operating on natural gas. FCE plan to extend their demonstration programme, develop products for the 10-50MW stationary market and expand its production capacity to 400MW in 2004. MTU are to have an aggregate capacity of 10MW of their technology running by end 2002.

  MCFCs have not apparently been demonstrated on biogas. However, FCE hopes to participate in the development of a 1MW MCFC plant to be operated at a wastewater plant in Renton, Washington[25]. This will run on digester gas from the plant's four digesters in 2002.

  The expected timetable for commercialisation of MCFC technology will depend on a number of complex and uncertain factors. It is unlikely that commercialisation will happen before 2006.

- *Solid Oxide Fuel Cell (SOFC)*
  SOFCs enjoy the same advantages as MCFCs, but are a simpler concept since all of the components are solid state. The disadvantages are largely materials issues and

stem from the higher operating temperature (800°C or more for the most developed SOFC concepts).

This fuel cell type is in a demonstration phase of development. The leading developers, Siemens Westinghouse, consider themselves in the final phase of development[26]. They have completed a 17000 hour demonstration of a 100kW SOFC unit at Westervoort, Netherlands[27]. Westinghouse are currently building a manufacturing facility for 2003 to deliver 250kW and 550kW SOFC units.

The use of SOFCs with biogas has received some attention in the literature[9]. However there do not appear to have been any demonstrations as yet.

SOFCs may arguably be the fuel cell of choice for stationary power generation in the long term. However, commercialisation before 2007 is unlikely.

Table 2. Characteristics of the Main fuel Cell Types

Type		PEMFC	DMFC	AFC	PAFC	MCFC	SOFC
Electrolyte		Sulphonic acid (proton exchange membrane)	Sulphonic acid (proton exchange membrane)	Aqueous alkali (usually potassium hydroxide)	Phosphoric acid	Molten carbonate mixture in $LiAlO_3$ tile	Solid oxide (usually yttria-stabilzed zirconia)
Transfer ion		H+	H+	OH-	H+	CO_3^{2-}	O^{2-}
Anode material		Platinum catalysed carbon	Platinum catalysed carbon	Platinum catalysed, PTFE- nickel mesh composite	Platinum catalysed carbon	Sintered Nickel-chromium	Nickel-zirconia
Cathode material		As anode	As anode	Silver catalysed, PTFE- nickel mesh composite	As anode	Nickel oxide	Lanthanum manganate
Operating temperature (°C)		70-80	70-80	80-100	200-220	600-650	800-1000
Current density		High	Moderate	High	Moderate	Moderate	High
Need for fuel processor		Yes	No	Yes	Yes	Yes*	Yes*
Compat-ibility	CO	No	No	No	Yes (1%)	Yes	Yes
	CO_2	Yes	Yes	No	Yes	Yes	Yes
	H_2S	No	No	No	No	No	No
Stage of development		Early prototypes	Research	Space application	Early commercial applications	Field demos	Laboratory demos
Current prospects	High effici-ency	Good	Poor	Good	Good	Good	Good
	Low cost	Good	Poor-fair	Good	Fair	Fair	Fair-good

A single fuel cell typically produces around 1 volt and, depending on the size of the cell and its type, typically of the order of hundreds of watts. In order to obtain practically useful voltages and power outputs, a number of fuel cells are combined in series or some combination of series and parallel connections. This unit is then known as a fuel cell stack. In this way, individual stacks of hundreds of kilowatts have been built up.

Hydrogen is the preferred fuel for fuel cells because of its high reactivity. Generally, fuel cells can run on other fuels only if they are first chemically converted to hydrogen either by a separate fuel processor or, in some cases, in the fuel cell stack itself. The exception to this is the DMFC, which utilises methanol directly.

The fuel cell stack comprises only part of a practical fuel cell generator. The other major components of the fuel cell system are a fuel processing section (in order to produce hydrogen as mentioned above) and a power conditioner. The latter is necessary to convert and control the power output of the stack (always d.c.) to match the requirements of the application (often a.c.). In addition, the need for cell cooling (to remove waste heat), control of the system and integration of it for maximum efficiency, means that there are numerous smaller items required, e.g. compressors, heat exchangers, sensors, etc.

Generally, fuel cells are regarded as most suitable for power generation at smaller to medium scale. This is because it is at these scales that factors other than purely cost/kWh become significant and mitigate against the higher capital cost of the devices. Applications such as distributed generation and on site power generation, areas expected to become more important in a growing electric power market, represent realistic opportunities for stationary fuel cells.

PEMFCs, MCFCs and SOFCs are the three fuel cell types expected to feature most, the latter two types due to suitability for natural gas fuelling and utilisation of waste heat, and PEMFCs due to the attainment of relative cheapness for transportation use.

2.3.3 Gas Turbines

The gas turbine is in principle a simple device. The concept is shown in Figure 4 and depends on the combustion of a fuel. In order to achieve this, a working fluid (gas) is required, and is pressurised by a compressor. Heat is supplied by the combustion of a fuel within a combustion chamber usually by homogeneous combustion, but catalytic combustion or even indirect heating is possible[40]. Heating of the gas mixture increases its temperature causing it to expand and increase in kinetic energy. Passage of the hot expanding gas through a turbine produces work. The majority of this work is used to drive the compressor and the remaining work can be used to drive a generator.

Turbines are classified according to the physical arrangement of the major components, for example: simple cycle versus recuperated or single shaft versus double shaft. Simple cycle gas turbines become more cost effective as the output and efficiency increases; this means that there is effectively a minimum size (usually around $4MW_e$). Exhaust temperatures of around 600ºC are likely, which means meaningful quantities of heat can be recovered for cogeneration applications. Alternatively, exhaust heat can be recovered to preheat fuel or air increasing electrical efficiency (the function of the recuperator in Figure 4). This lowers the practical minimum size for the generator, but means less heat is available in cogeneration applications.

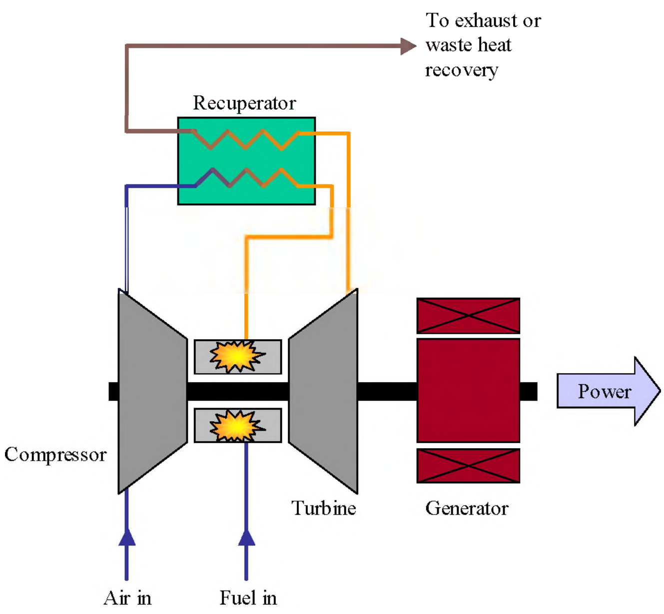


Figure 4. Operating Principle of a Gas Turbine

Increasing the temperature or pressure of the working fluid can be used to increase efficiency. Operation at elevated temperatures and pressures reduces component life and can increase some emissions. The tolerance to some of the components present in biogas may decrease due to increased reactivity. Smaller simple cycle turbines generally have a low efficiency, however, some of the exhaust heat can be recovered using a recuperator

Microturbines are derivatives of the turbocharger. They are small (output range is 28kW-200kW), single shaft, recuperated gas turbines. They are a relatively advanced technology, being commercially available. There are a number of manufacturers of including Capstone Turbine Corporation, Ingersoll Rand, Elliott/Bowman and Turbec. Most of these manufacturers are planning annual production volumes of 10000-100000 units.

All gas turbines inject fuel into the burner, within the compressed air chamber. The fuel delivery pressure must be greater than the chamber air pressure to ensure fuel delivery. On simple cycle turbines the pressure ratio is likely to be in the range 10 to 40. On recuperated turbines such as the microturbine, the pressure ratio is lower and can be as low as 3.5 on commercial systems.

All microturbine manufacturers see power generation from renewable energy and biogas as a significant market opportunity. Combustion temperatures of around 900ºC to 1000ºC are sufficiently low to allow microturbines to be tolerant to most compounds potentially present in biogas. Heat can be recovered from the exhaust in cogeneration applications, however the temperature is lower than that of the simple cycle turbine.

Capstone's microturbine business is growing rapidly. So far, they have shipped more than two thousand $30kW_e$ units and have introduced a $60kW_e$ model[29]. At the time of writing the only the $30kW_e$ system has a variant suitable for low CV fuel applications. The $60kW_e$ turbine is a recent addition to the product range and is likely to be modified to operate on low CV fuels in the future. The Capstone landfill gas/digester gas package will operate on fuels down to $13MJ/m^3$ and can be sulphur tolerant[30].

Significant numbers of Capstone microturbines have been sold to biogas applications. The largest single project is run by the Los Angeles Department of Water and Power and uses fifty 30kW units to generate power from landfill gas[31]. Other large projects include ten 30kW units installed at the City of Burbank's landfill, California[32] and twelve 30kW units at the City of Allentown Wastewater Treatment Plant, Pasadena[33].

Honeywell manufactured the Parallon microturbine system[153], which has an output of $75kW_e$. Several trial units have undergone a period of testing on on low CV fuels such as the landfill gas trials at Albuquerque, New Mexico[34] and Nepean, Ontario[35]. Trials on sour gas have also been undertaken. These trials were generally successful however the Parallon system was less tolerant to sulphur than the Capstone products. Honeywell shipped a total of around 300 units in 2000[36]. In 2001 they made an announcement withdrawing from the microturbine market. The existing units are now being recalled. This is the first withdrawal of a manufacturer from this emerging market sector

Ingersoll Rand is currently commercialising its PowerWorks microturbine product line. It has placed a total of ten pre-commercial 70kW units for field-testing in 2000 and early 2001[36]. Commercial production is planned for the second half of 2001. The PowerWorks system differs from other designs in that it utilises traditional fixed speed generator technology as used on reciprocating engine gensets. This requires the turbine to be connected to the generator via a gearbox. The generator speed is proportional to the frequency output and the initial commercial models will be 60Hz. It is anticipated that the European 50Hz model will be commercialised 6 to 12 months behind the 60Hz US version.

Bowman Power Systems is developing its Turbogen family of small-scale power generators based on the Elliott TurboAlternator. The Bowman packages are particularly aimed at the cogeneration market. Outputs for this technology are 25-80kW. Bowman's $50kW_e$ and $80kW_e$ packages are close to commercialisation. These units run on a variety of fuels including natural gas, LPG, propane, butane and liquid fuel. Tests using biofuels on pre-production systems are underway. It is expected that biofuel systems will be available in approximately 1 year.

Turbec is a joint venture between ABB and Volvo to supply cogeneration units to the European market. By early 2001, they had shipped twenty units. The Turbec microturbine has an output of 100kW$_e$ and is offered as biofuel compatible. This product has been commercially available for a short period and no biogas systems have been installed in the UK or overseas, although a small-scale prototype system has operated on a low CV fuel for several years. Volvo have also operated the turbine on methanol, developed from renewable sources.

Derivatives of aero gas turbines are available below 1MWe. At smaller sizes, the simple cycle turbines tend to have efficiencies between 15% and 20%, but efficiency can be increased by using a recuperated cycle to recover some of the exhaust heat. A new generation of recuperated aero-derivative gas turbine will become available in the near future. The first system will be introduced by a collaboration between TurboGenset, Pratt&Witney and Detriot Edison. The output from a single turbine will be 400kW$_e$, however it is anticipated that many systems will comprise of 4 turbines with at least 3 in operation at all times. The efficiency and cost/kW$_e$ are similar to those quoted by some of the turbine manufacturers

2.3.4 Stirling Engines

The Stirling engine is a closed cycle regenerative heat engine that uses an external combustor as a heat source. It works on the physical principle of the expansion of a heated gas causing a piston to do work. In this way, it is related to the internal combustion engine, but the key difference is the external supply of heat to the working fluid (gas) through a heat exchanger. Therefore, the Stirling engine is an external combustion engine.

The principle of operation of the Stirling engine is shown in Figure 5. The engine consists of two pistons, one in a hot zone and one in a cooler zone. The Stirling cycle can then be idealised as four distinct thermodynamic steps:

- *Constant volume heating*
  The mechanism of the engine forces the working fluid from position d) to position a) through the regenerator, essentially a heat sink, which has stored a portion of the heat contained in the working fluid during a previous cycle. Heat is transferred back to the working fluid causing the pressure of the confined fluid to increase.

- *Isothermal expansion*
  In position a), heat produced by combustion of a fuel is transferred from the hot zone to the working fluid. The gas expands forcing the hot piston out to its maximum extent (position b).

- *Constant volume cooling*
  The mechanism of the engine then moves to position c) forcing the working fluid through the regenerator again. This transfers some heat to the regenerator, causing the working fluid to cool at constant volume and reducing its pressure.

- *Isothermal compression*
  The cold piston moves to position c) compressing the gas at the temperature of the cold zone. The cycle then repeats.

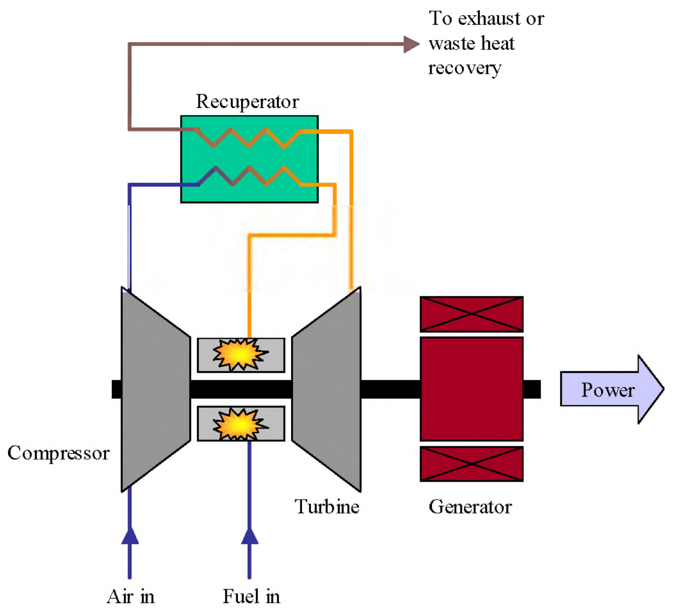


Figure 4. Operating Principle of a Gas Turbine

In passing through one cycle, work equivalent to the work done by the expansion piston minus the work done in compression piston is available for power generation. Since the pistons are linked by a rotating shaft, this work can be taken out by a generator linked to this shaft.

Stirling engine technology is currently under development. Outputs are likely to range from <$1kW_e$ to around $30kW_e$. The main advantage of the Stirling cycle is the use of an external combustor that can easily be modified to operate on a range of fuel types. The smaller sizes of Stirling engine are becoming commercially available with larger systems likely to become available in 2003. At present the costs are high and the technology is not economically attractive for this application. The larger systems could prove highly attractive for this application if costs targets can be met.

Domestic CHP, fuelled by natural gas, is no longer just a research concept. In the UK, BG Group have unveiled a prototype 1kW$_e$ Stirling engine-based unit at an advanced state of development. New Zealand based WhisperTech are in a similar position with a Stirling engine based product already on sale as a DC version for the leisure market. A 3kWe Stirling engine-based unit has been demonstrated by Sigma in Norway and a larger (10kW$_e$) unit is now available from Solo in Germany.

The relative fuel flexibility of Stirling engines means that they are potentially suitable for a wide range of renewable applications and have been suggested for small-scale power generation using biomass[4].

2.3.5 Hybrid systems

There are a number of possibilities for combining the technologies discussed so far to form hybrid systems. Of these, high temperature fuel cell - gas turbine hybrids have received most attention recently, largely because of their potential to provide electrical efficiencies of at least 70%[37], possibly up to 80%[38]. The concept is shown in Figure 6 and relies on combustion of the relatively low CV fuel cell exhaust in a gas turbine system in order to further increase already high system efficiencies. SOFCs have received most attention in this type of system, but MCFCs have also been developed[39].

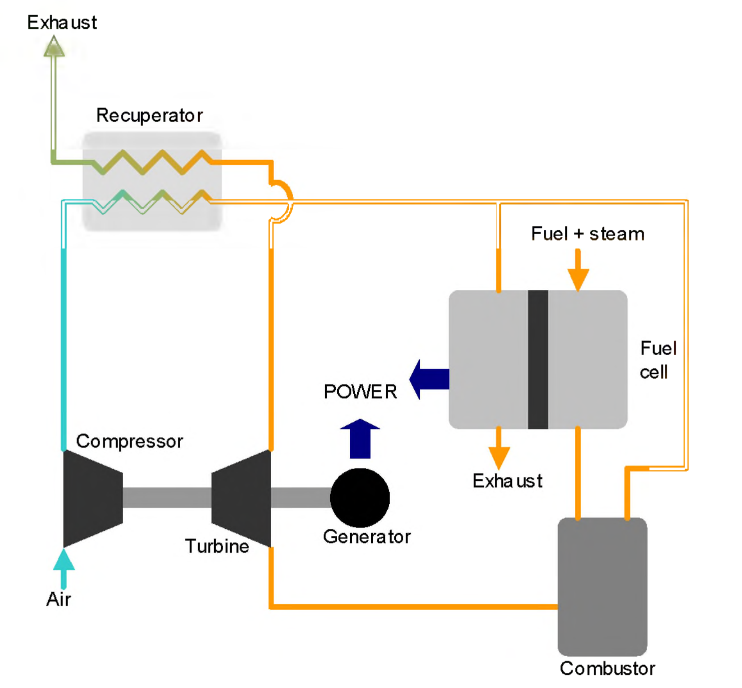


Figure 6. Generic Fuel Cell – Gas Turbine Hybrid System

Siemens-Westinghouse holds a lead in SOFC/turbine hybrids. They have built and successfully factory tested the World's first fuel cell/turbine hybrid[28], a 220kW unit with 60% efficiency. FuelCell Energy is the leading developer of MCFC/turbine hybrids. They have recently commenced operation of 250kW generator incorporating a capstone turbine unit in the US[121].

No fuel cell/turbine hybrid systems have been tested on low-CV fuels. However, the concept has been recognised and investigated theoretically[9]. Efficiencies of up to 58% have been shown to be possible when integrated with biomass gasification. Commercially available systems are unlikely to appear until at least 2008.

2.4 Biogas Fuelling Technical Issues

BDG brings together biogas and power generation technology. This brings further technical issues, which must be addressed. A significant point evident from Table 1 is that biogas is a 'sour' gas, because hydrogen sulphide is present potentially at a high level. This is an issue because hydrogen sulphide is harmful to some generating technologies either directly or through combustion to form corrosive, acidic sulphur dioxide, which can attack engine components. A number of biological, chemical and physical methods of reducing the concentration of hydrogen sulphide are possible[118], none being ideal. Some remedial measures are commercially available, for example, the biogas scrubber marketed by Apollo Environmental Systems Corporation[17]. However, these add cost and complexity to power generation systems. Furthermore, the efficiency claimed for these devices means that sulphur would certainly still be an issue for certain sulphur-sensitive technologies even after passage through the scrubber.

The sulphur-corrosion issue has long been known in ICEs. Sulphur-tolerant versions are available that are capable of running on fuels containing up to 6% sulphur[116]. A common ploy is to supply normal natural gas to the unit as well as sour gas. Each time the unit is to shut down, it is first run for a short time on mains gas. This ensures that the system from cylinders to exhaust is not left containing a moist, acidic environment, normally a recipe for metallic corrosion. A similar procedure should be possible with other power generation technologies, when run on particularly sour gas.

Sulphur is a particular issue for fuel cells, poisoning electrocatalysts and fuel processing catalysts. The limit of sulphur tolerable in the fuel cell is less than 1ppm. For this reason, natural gas-fuelled fuel cells always include sulphur removal technology aimed at removing a few tens of ppm of sulphur from the fuel. The presence of sulphur at a level up to three orders of magnitude higher than this is a particular problem for fuel cells and would certainly mean a heavily uprated sulphur removal section or external sulphur removal stage capable of reaching down to sulphur levels of the same order as is present in natural gas.

Corrosion from acidic species and certain metal ions potentially present in biogas is a potentially serious problem for microturbines, because high-temperature components rotate extremely rapidly (around 100000 rpm). In practice, conservative operating temperatures minimise this. The capstone biogas model is reputed to be tolerant to biogas of up to 7% hydrogen sulphide content.

It is worth noting that combustion of sulphur present at its highest level in biogas, equates to sulphur dioxide emissions rivaling those from coal-fired steam plant without flue gas desulphurisation. This would seem to be inconsistent with the environmental driver, which is important for this application, and this may raise issues such as permitting. Consequently, all of the technologies would require some form of sulphur capture when operated on the most heavily sulphur-laden biogas.

Ammonia is a further pollutant frequently present in biogas at low levels (a few ppm). None of the technologies considered are sensitive to ammonia apart from acid electrolyte fuel cells (PEMFC and PAFC). Here, ammonia has been recognised as a problem when formed in fuel processors in relatively high quantities from nitrogen present in low quality natural gas. Hence, the nitrogen present in biogas is of more concern to low temperature fuel cells than ammonia as such and would likely require the inclusion of an ammonia absorption process stage. None of the other technologies are harmed by nitrogen.

Chlorides too are a particular problem to fuel cells. Since chlorides are rarely present in natural gas, standard fuel cell systems are unlikely to be equipped with sufficiently large adsorbent beds. Additional measures will generally be necessary. For example, pre-treatment units have been used to reduce sulphur and halide concentrations to less than 3ppm in order to operate PAFCs on landfill gas[169].

In addition to consideration of the deleterious effect of certain substances, the calorific value of biogas is lower than that of natural gas as there is a high level of carbon dioxide present and very low levels of higher hydrocarbons. The operation of the unadjusted technologies on biogas can mean a lower power output and lower efficiency than would be achieved with natural gas. For example, the PC25 PAFC fuel cell is a 200kW$_e$ device, but operation on landfill gas with an enthalpy of 20.8MJ/m^3 gave 140kW$_e$, and only 120kW$_e$ when the heating value was 16MJ/m^3. The efficiency also dropped one percentage point[169]. The lower CV of the fuel does not reduce the output or efficiency of microturbine based systems, however the fuel throughput must be increased to maintain heat input. This causes an increase in the parasitic loads of the system. Use of low CV fuels in reciprocating engines does not affect performance. The air fuel ratio must be modified when gas engines are adapted to operate on low CV fuels but there is no increase in parasitic loads or net effect on engine performance. There can be an increase in operational costs however, as the contaminants mentioned above, can accumulate in the engine oil. Build up of sulphur will make the oil more corrosive, which could reduce engine life.

As biogases are produced at low pressures, a booster is required to increase the pressure for fuel delivery to certain of the technologies, particularly microturbines. This pressurisation stage adds a parasitic load to the system. As the heat input into the turbine is fixed for a specific output and the CV of the fuel is lower than that of traditional fossil fuels, a higher volume of fuel (or higher pressure) is required. The parasitic load from the compression stage is higher than that normally expected for a fossil-fueled system. The gas booster is exposed to the same contaminants as the rest of the power generation system. At present, there are few manufacturers that supply biogas tolerant equipment. Recent trials have shown that compressor reliability is a major issue.

Use of low CV fuels in all types of combustion system will affect the emissions. If a system is properly set up the emissions of most pollutants should be reduced as the fuel is diluted and peak temperatures are slightly reduced.

Overall, each technology is capable of operation on biogas. Combustion-based technologies such as microturbines are likely to require minimal preprocessing or none at all when operated on most biogases. Fuel cells will require significant preprocessing. Consequently, they will have to bear a significant extra capital cost for this application. For example, a preprocessing unit for the PC25 cost \$1700/kW-\$2500/kW[169], although this figure would be lower with volume production.

2.5 Generation Technology Comparison

The characteristics of the various available technologies for use on biogas are given in Table 3. A major market driver will be costs, both capital costs and operation and maintenance (O&M) costs. The table indicates that ICEs currently have the lowest capital cost, largely a consequence of volume production. However, there is relatively little scope for further cost reduction of this mature technology. Microturbines have the potential to match or beat these low costs.

The highest electrical efficiencies are offered by the relatively immature fuel cell-gas turbine hybrids. These offer the potential of 70%+ efficiency, around twice that of microturbines. Microturbines, Stirling engines, ICEs and small-scale steam plant all have relatively low efficiencies. Efficiencies of ICEs of comparable capacity to microturbines when operated on biogas have traditionally been less than 25%[159], comparable to the Capstone landfill gas microturbine. It is worth noting that differences in overall efficiency of cogeneration units are not so wide. Hybrid systems are likely to be focused more on power-only application.

Table 3 shows that the technologies possess diverse characteristics, with no technology a clear technical superior. The diversity of DG users' needs will mean that a market for each technology will be likely. At the same, it is important to realise that the market for BDG will not be so diverse, particularly while biogas represents a relatively minor fuel. Table 3 contains sufficient information to determine the likely future technological scenario.

ICEs are the most developed power generation option for use with biogas. Historically this has been the natural technology choice for BDG simply because there was little alternative. For example, in a case study of 19 farm-based digester projects for the "Methane Recovery from Animal Manures" casebook[41], engines were the only power generation technology represented.

New and emerging technologies will undoubtedly change this situation and make inroads into the market. The cost of these technologies will be a major consideration for the power generation option and will have a significant impact on the overall economics of new biogas projects. Currently, microturbines are the cheapest new technology and will compete well with engine technology in this application, growing their share of the market as production is ramped up and costs come down further. PAFCs are an expensive option and have remained so since their first introduction. On this basis, they are unlikely to find a large biogas-fuelled market despite rather better efficiencies than microturbines.

The remaining types of fuel cell are generally next-generation technology, but if developers' plans are to be believed, will become commercially available between 2003 and 2008, depending on type. Historically, the fuel cell community has not met its targets. Nevertheless, developers' plans are sufficiently advanced now to give some credibility to the current timetable.

In the years after commercialisation, capital costs will tumble, but given the head-start microturbines have, fuel cells will certainly remain a relatively expensive option for a number of years, competing more on cost of generation, high efficiencies mitigating higher front-end costs. This will be particularly true in biogas application where the relatively poor technical fit for the linkage will generate additional fuel processing costs. Nevertheless, the particular attributes of fuel cells (particularly SOFC and MCFC) as highly efficient, near-zero SO_x/NO_x emitters will make them attractive for biogas application as costs come down, and they will undoubtedly compete well in the second half of the period to 2020.

The prospects for conventionally fuelled and biofuelled microturbines appear to be bright in the short and medium term. Their advantages of modularity, projected low cost and small size will mean that they will compete well with current ICE technology. However, significant weaknesses in microturbine technology are low efficiencies and inability to reach down to low power ratings.

Table 3. Comparison of Major Characteristics of Small-Scale Power Generation Technologies

Tech-nology	Power range	Costs		Efficiency (%LHV)	Emissions (g/kWh)		Commercial status	Biogas technical fit
		Capital[e] ($/kW)	O&M (c/kWh)		NOx	SOx		
Steam plant		1900[a]	3.0[a]	28[a]	0.14-0.45[h]	Note g	Fully mature.	High.
IC Engines	5kW-60MW	400-750[c] (350-650)	0.7-2.0[c] (0.5-1.3)	24-37[c] (26-47)	0.68-16[f]	Note g	Fully mature. Biogas units available.	High. Sulphur tolerant units available.
Turbines	1-50MW	700-900	0.3-0.8	35 (45)	3.2-4.1	Note g	Nearly commercially available.	Medium.
Micro-turbines[d]	25-500kW	720-900 [c] (320-600)	0.5-1.0 [c] (0.1-0.2)	17-30[c] (23-42)	0.23-2.3	Note g	Recently commercialised. Biogas units available.	High. Sulphur tolerant units available.
PEMFC	1-250kW	(200-300)[i]	0.2-1.5	42	Negl.	Negl.	Precommercial units	Low due to sensitivity to contaminants.
PAFC	200kW-2MW	3000	0.2-1.5	39-44	Negl.	0.0073[f]	Commercially available. Demonstrated on biogas.	Low due to sensitivity to contaminants.
MCFC	250kW-2MW	(1000) [i]	0.2-1.5	46-60	<0.0009[f]	<0.0014[f]	Field trails.	Low-medium due to sensitivity to contaminants.
SOFC	250kW-5MW	(600-1000) [i]	0.2-1.5	50-65	Similar to MCFC	Similar to MCFC	Field trials.	Low-medium due to sensitivity to contaminants.
SOFC/ MCFC-GT	250kW-20MW	(1000-1500)[c]	(0.4-1.4)[c]	~60 (70-75)[c]	0.022-0.027[f]	Negl.	Factory tested. No demonstrations on biogas.	Low due to sensitivity to contaminants.
Stirling engines	1-30kW	2400	2.0	22[b]	0.05	Note g	Commercially available.	High.

[a] For a 50MW plant (from ref 117).
[b] From ref 4.
[c] From Reference 142.
[d] Including unrecuperated microturbines.
[e] For power-only units. For CHP units, add ~150$/kW for engines and 30% for turbines. Little difference for fuel cells, which are generally CHP units.
[f] From ref 174
[g] Values for combustion-based devices will be highly dependent on sulphur content of fuel. For natural gas fuelled systems, this will be typically less than 0.05 g/kWh. Biogas-fuelled units may approach 20 g/kWh.
[h] From reference 47.
[i] From refresence 175.

3. Markets

3.1 Applications for Biogas-Fuelled Distributed Generation

This section discusses the main stationary power DG applications, their requirements and how these relate to BDG.

3.1.1 Power-Only Distributed Generation

Off-Grid Generation

General requirements for off-grid power are reliability and simplicity of operation (including low maintenance). Off-grid applications effectively cover a range of applications, often at small scale. Many applications will supply energy to a single remote user. There is the potential to develop mini-grids to supply biogas to small, localised communities that are not connected to the natural gas network.

Remote power involves the use of small power sources in locations far from any electricity or fuel infrastructure. In OECD-type countries, this may be basically a niche market. For example, in the US, there may be 20,000 such sites for power plant of around 20kW$_e$ capacity (only 400MW$_e$ total)[93]. In the UK there are large rural areas such as Devon and Cornwall that are poorly served by the natural gas transmission system. Here, biogas could potentially displace higher-cost fuels already in use, which would improve the economic viability on any installation. As the main industry in many rural sites is agriculture, a high proportion of sites will have suitable energy requirements and be capable of supplying feedstocks to generate biogas.

The global market for rural power is potentially very large. Two billion people are currently without access to power by wire, mainly in developing nations. Although village electrification schemes would attract grant funding, the cost of the technology is likely to make many projects uneconomic. In OECD-type countries energy availability is such that the off-grid market is likely to be small. Where there is an off grid energy need, there is a choice of fuels already available with which biogas must compete. These fuels are lower cost, readily available and have an existing supply infrastructure.

Replacement of batteries in uninterruptible premium power is seen by many as an important emerging market[93,134]. Examples already existing include a fuel cell system powering a bank with 99.9999% availability[135]. It is usually the high-tech industry that places high value on power quality. This industry does not generally produce much biodegradable waste. The demand for increased power quality in rural areas linked to the availability of suitable feedstocks could make this an attractive niche market.

Domestic scale power generation in urban residences is an application that could become significant if DG technologies become cheap enough to make deferral of grid connection costs worthwhile in new homes. To supply this market with biogas would require the use of the existing gas transmission and distribution system. There are some technical and cost issues that must be overcome to make upgrading of biogas to pipeline quality a viable proposition. As the total potential for biogas production is relatively small when compared to natural gas consumption, blending of the fuels is seen as the most viable option at present.

Embedded Generation

Embedded generation is defined as plant connected at distribution system level and not subject to central despatch[43]. As is the case for central-station plant, the cost of generated electricity is obviously an important factor that determines the competitiveness of embedded generation. However, non-quantifiable factors such as cycling ability, ease of siting (particularly important in minimising grid connection costs) and ability to meet local emissions standards come more into play[44]. Furthermore, embedded plant is frequently located on users sites where further site-specific factors will be important. Again the cost of generation is important and users will opt for the lowest cost option that is a solution to their power generation needs. These needs might include high reliability power, high power quality or low noise/emissions. A market for BDG is likely here where suitable waste supply is available.

3.1.2 Combined Heat and Power Distributed Generation

Combined heat and power (CHP) represents the bulk of the growth in fossil-fuelled DG in developed countries[114], driven both by economies resulting from heat recovery and environmental benefits of the resulting high overall efficiency. For example, CHP in the UK has grown on average 6.6% per year over the last six years (c.f. 1% for power plant in general). CHP accounts for around 6% of global generation capacity[136].

Optimum advantages of CHP are often achieved when the unit is sized according to the local heat demand, frequently resulting in excess electrical power[137]. Economics dictate that this be exported. Therefore, grid connection issues (usually barriers) such as those discussed in Section 3.2.1, impact significantly on the outlook for CHP. However, government initiatives such as those described in Section 3.2.1 are major drivers for CHP, ensuring that CHP is set to grow significantly in the geographical regions considered.

CHP spans a broad power range. For example, in the UK projects range from considerably less than 100kWe to large projects well in excess of $100MW_e$[138]. The UK market is skewed towards smaller facilities in terms of numbers of installations. The situation is completely reversed when installed capacity is considered, the 81 sites over $10MW_e$ dominating the picture.

The use of CHP from landfill gas is currently limited by the availability of heat loads near to the landfill site. This form of generation may still find application by delivery of biogas to the relatively small number of adjacent heat consumers. Furthermore, wider recognition of growing landfill gas utilisation may grow this number of users (e.g. in the so-called ecoindustrial parks[122]). By contrast, CHP is the most natural application for biogas from purpose built digesters; heat recovery from the generator can be used to heat the digester and adjacent facilities.

All the biogas-fuelled power generation technologies discussed in Section 2.3 have waste streams containing recoverable heat and are therefore applicable in CHP. On many sites there will be a demand for power, but also a demand for heat. A large future market for biogas-fuelled CHP is highly likely, driven by the need to meet national targets for both CHP and renewable energy.

3.1.3 Operating Regimes

In principle, CHP and power-only generators may fulfill several different duties. These are baseload, peaking and standby generation. Baseload represents the supply of the minimum continuous demand and is essentially a high utilisation application. Emerging DG technologies are well suited to this mode of operation, high reliability offering the possibility of utilisation of more than 8000 hrs/year. At present, in contrast to the situation in developing countries, there is little market for power-only baseload DG in OECD countries[114]. This tends to be confined to areas not served by the more competitive alternative – power by wire. However, new technologies may well change this situation by offering beneficial cost of electricity and enhanced reliability.

By contrast, peaking and standby generation represent less than 1000hrs/year utilisation[114]. Power is produced when the value of electricity is high and a less stringent cost/kWh is demanded of the generator. Some have suggested that this mode represents the best opportunity for DG[139]. However, whilst peaking with diesel generator sets is generally accepted, the use of new technology may have to rely on favourable regulation[114]. In any case, the requirements are for a flexible generator, able to respond quickly. Not all DG technologies are capable of this e.g. high-temperature fuel cells.

Within these two extremes lies plant providing neither true baseload nor true peaking, but utilised for a few thousand hours per year. This might involve extended runs followed by extended down time, as a strategy against electricity price volatility. Engines (mostly 500kW-3MW[140]) currently serve the market, turbines at higher powers.

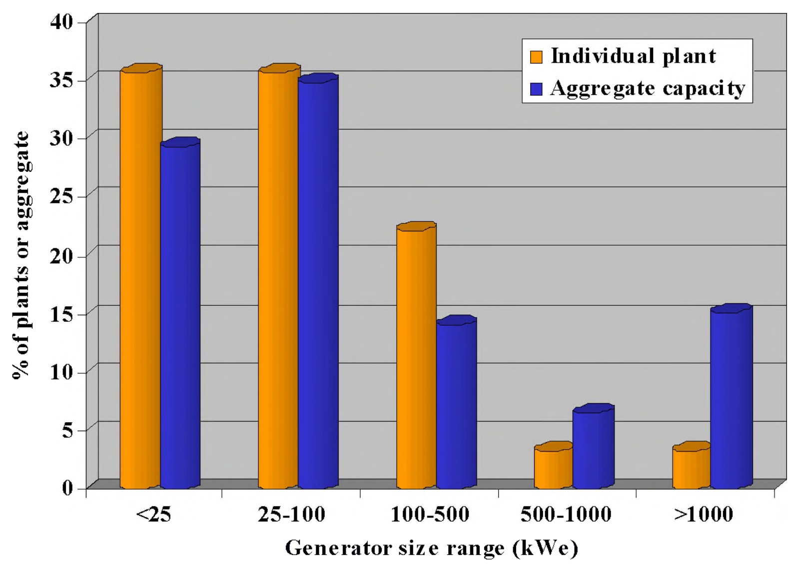
Some users will undoubtedly use BDG for low utilisation applications. However, power generation from biogas is most naturally baseload, largely because the AD process is continuous rather than stop-start and because the feedstock material is frequently waste material, usually being produced continuously. This is how electricity from biomass has been traditionally used[117] and how the majority will likely be used in the future, competing with power-by-wire on improved economics and non-quantifiable benefits.

3.1.4 Generating Plant Scale

The scale of biogas projects is a significant parameter since it sets an upper limit on the size of electrical generator applicable. AD can be carried out on-site, relatively small-scale projects utilising feedstocks produced on-site. Larger, centralised AD projects utilise feedstocks from a number of sources. These are more likely to use the thermophilic process and typically produce of the order of 12000m^3 of biogas daily[125]. This scale is particularly prevalent in Denmark[165].

According to the AD-NETT database[168], the profile of European plant sizes is skewed towards smaller projects, 55% processing 25m^3 of slurry per hour or less, enough to operate generators of the order of 30-50kW_e. The profile of generator sizes employed is given in Figure 7. Some 70% of the generators are of 100kW_e or less. Larger plants become more significant when total aggregate capacity is considered. The introduction of highly efficient small-scale plant, together with favourable evolution of technical and commercial aspects of grid interconnection will likely push this profile towards slightly larger generators. Nevertheless, it appears that the major opportunity will remain at medium-scale, say around 200kW_e or less.

Figure 7. Profile of European AD Electrical Generator Size



Landfill sites typically produce sufficient biogas to support much larger electricity generation projects. In the UK, the average installation size is around 2MW with a trend for 1MW modules[16]. However, projects appear to range up to around 12MW[138]. Projects are typically rather larger in the US where a 3MW average applies[122].

3.2 Market Drivers/Barriers

The market for biogas-fuelled DG will effectively be a subset of the much larger market for DG as a whole, but at the same time a subset of the market for renewable energy. The significance of this observation is that this market will be subject in varying degrees to the particular drivers and barriers of both its parent markets, some common and some not. It is therefore pertinent to review the relevant factors controlling the wider market for DG before focusing on the particular characteristics of the bio-fuelled sector. These factors are shown in Figure 8 and discussed below.

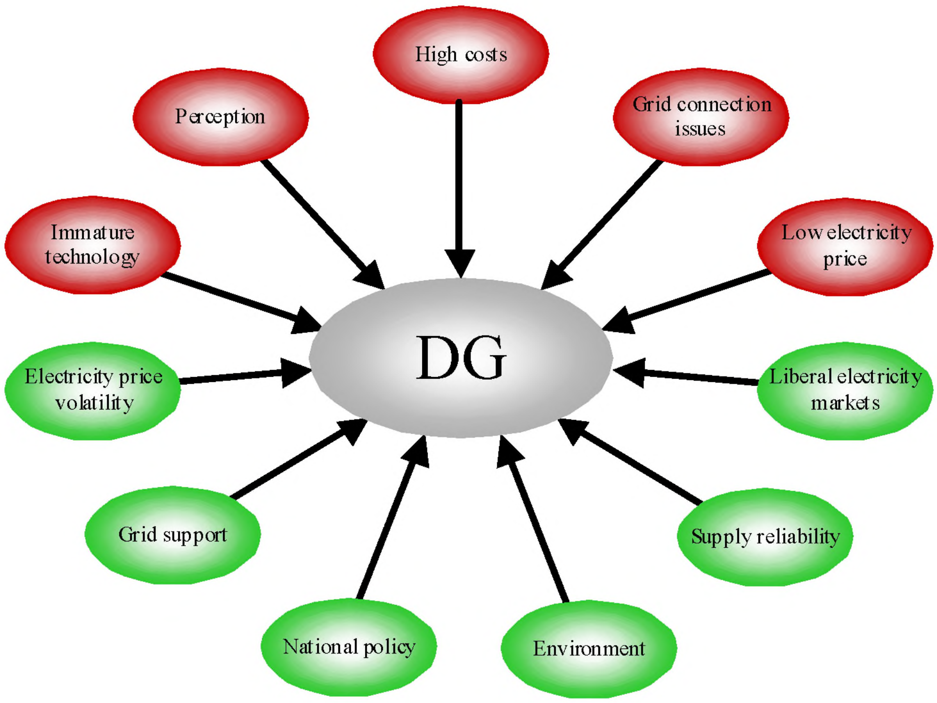


Figure 8. Distributed Generation Market Drivers (Green) and Barriers (Red)

3.2.1 Distributed Generation as a Whole

The many factors shaping the outlook for DG are mostly related to the benefits and disadvantages of the concept. These depend very much on which interest group is considered[43,44]. A number of factors are driving the realisation of these benefits, but market barriers stand in their way. The major factors are discussed in this section.

New Technology

The contribution of DG, particularly CHP and renewables is generally growing in developed countries. The introduction of the next generation of DG technologies together with a wider market acceptance of technologies in an early commercial stage will be required to accelerate the pace of change and grow the market for fossil-fuelled, power-only DG. The main technologies involved and their principle attributes are those listed in Table 3 together with renewable energy technologies such as wind turbines and photovoltaics. Notably, a number of fossil-fuelled technologies - those offering the most attractive environmental benefits - currently have capital costs too high to stimulate volume sales. In some cases, high efficiencies will mitigate against higher capital costs, but significant cost reductions will be necessary for widespread market acceptance. Clearly, major cost reduction and efficiency increase must remain major development goals. These facts highlight a major uncertainty concerning future markets: technologies having the power to shape the future markets are relatively immature, the future market volume depending on the degree to which cost and performance targets will be met by developers.

Costs

Cost represents an important consideration since users will opt for the least cost alternative that serves their power needs. In this respect, there will be no single answer to the question of which power supply option is most cost-effective since the determining factors are site-specific. Some may see first cost as the most important consideration, in many cases opting to continue with power-by-wire. Others will consider the whole lifecycle cost incorporating installed capital cost, fuel cost, operation and maintenance, utilisation, siting and environmental costs etc[45]. Some commentators see many DG technologies competing head-to-head on cost (depending on scale) with combined cycle gas turbines by 2010[46]. However, it may be more likely that some renewable technologies and fuel cells will remain rather more expensive than turbine technology[47], competing on overall lifecycle cost and non-quantifiable benefits.

A significant corollary of DG muddies the waters somewhat: DG-associated costs are borne essentially by the user, but not all of the benefits accrue to that user[48]. Nevertheless, an increasing number may choose the DG option as expected reductions in costs are realised. For others, where existing power supplies cannot meet the local need, DG will be the preferred option almost regardless of cost (a bank in Omaha, US, was able to purchase a fuel cell system, normally an expensive option, for about the cost of only a one hour power outage[49]).

The location of DG could be a critical factor for DG users. Avoidance of T&D costs can be a large saving: in the US, 0.16-6c/kWh, 0.23-0.31c/kWh and 0.07-0.17c/kWh for substation deferral, transmission losses and distribution feeder deferral respectively[50]. Typical grid interconnection costs are $50-$200/kW depending on the size of the installation and utility requirements[51]. Amortised over five years of baseload operation, this could represent 0.16-0.64c/kWh – i.e. avoided T&D costs are significant compared to connection costs. Proper siting of DG and recognition of financial benefits to both customer and distribution network operator will be critical to the acceptance of many DG projects.

Environmental costs represent a significant wildcard. Environmental initiatives that have been considered include energy/carbon taxes and emissions trading schemes. Against this background, the economic case for some DG technologies stands to gain, because they emit lower amounts of carbon dioxide, NO_X or SO_X than some conventional power generation.

In the UK, governments have traditionally made only minimal use of economic instruments to influence the use of energy. But, following a recent review[52], the government announced in its 1999 budget, the intention to introduce the 'climate change levy'[53], a tax on the business use of energy. This will provide only a small incentive for efficient, power-only DG over central power. The exemption of new and renewables and 'good quality' CHP from the scheme will give these a larger fillip.

In addition, the current UK government sees emissions trading as a key longer-term economic measure[53]. It has received outline proposals for an emissions trading scheme[54] for implementation well ahead of international emissions trading allowed for under the Kyoto Protocol. The future development of such a scheme and that of the 'climate change levy', and the degree to which such systems may be extended to include gaseous emissions other than carbon dioxide (e.g. SO_X and NO_X) are important unpredictable factors which can affect DG economics in the UK.

Similar considerations exist elsewhere. For example, systems of tradeable emissions permits have been used for some time in the US. Here, as elsewhere, the issues are slow approval (or denial) of DG projects and the implications of a vastly expanded future trading system. The EU too intends to introduce carbon dioxide emissions trading ahead of that provided for by the Kyoto Protocol[55], and is currently in a consultation phase, implementation being intended for 2005.

Thus systems are in place or are being developed that will economically favour efficient DG. The way these will evolve to 2020, and the degree to which these will exempt or favour particular DG technologies, will not only influence the uptake of DG as a whole, but will help to determine the future technology mix within DG.

Grid Connection Issues

As mentioned above, DG in OECD-type countries will frequently need to be grid-connected. This results in a technological barrier external to the power generation devices themselves. Distribution systems, together with the engineering standards that relate to them, were never designed to cope with embedded power which places local demands on the system and adds to the fault level on the system each time a generator is added[48,56,57]. This leads to the simultaneous evolution of the distribution system itself as more generation is embedded in it (for example, the addition of active control systems[58]), effectively acting as a brake to market growth.

The central technical issue is whether standards can be developed that will support the cost-effective interconnection of distributed generators without jeopardising safety and reliability throughout the electrical system[51]. This is a subject that appears to have received the most recent literature attention in the US where it has been suggested that the lack of simplified, low cost interconnection is the largest barrier to DG[45]. Attempts to develop uniform interconnection standards have been made in several cases at state level [e.g.59-62]. Interested groups such as the DPCA and the US Fuel Cell Council support the introduction of national interconnection standards[63-65]. Also, the Institute of Electrical and Electronic Engineers, supported by the US DoE are actively engaged in developing uniform standards at national level[66]. However, these are not expected to be available before 2002[51].

In the UK, there are national standards for planning and connection of embedded power in the form of the 'distribution code', incorporating various engineering recommendations[57]. Here the issues are more that the system was never set up with high levels of DG particularly in mind (several of the engineering standards date from the 1970s[67]) and that recommendations are open to interpretation. For example, it is recognised that the engineering standard, P2/5, needs to be revised so that the potential of embedded generation to enhance network security is fully exploited[68].

Grid connection issues extend beyond the technical problems of the linkage. Connection issues are essentially barriers to DG and include elements of process and contract[51]. The process introduces significant barriers to DG. Utility pre-connection studies and procedures detract from the attractiveness of projects by introducing delays and added costs. Contract means the commercial aspects of the connection e.g. the relative rates for supply via the linkage and purchase of excess power.

A significant American study[69] focused on 65 case studies, mostly of 1-26kW projects seeking to connect to distribution grids. 90% of projects experienced major utility-related barriers including lengthy delays, high connection costs and impractical appeals processes. In some cases, these difficulties were severe enough to kill the project. Many projects were delayed for months, some for many years. Added costs were frequently \$100s/kW, occasionally more than \$1000/kW. Similar delays are the norm in the UK, with typical connection timescales being 4-18 months depending on connection voltage[70].

In the UK too, barriers to DG connection have been a contentious issue in recent years. Problems that have arisen include inconsistent connection rates and commercial issues surrounding the marketing of excess power[71]. Interested parties perceive the fact that there is no real regulatory regime that encourages network operators to connect embedded generation as being fundamental to the problems[58]. Many of the issues surrounding the use of embedded generation have been explored by interested groups[eg 72] and are currently being debated nationally via a DTI/OFGEM working group[73]. Consequently, some of the issues may well be solved in DG's favour in the coming years. Also, the introduction of the New Electricity Trading Arrangements may well solve or ease some of these problems, but may introduce others. For example, some network operators have been concerned about incurring added costs during network faults[58].

Many DG technologies will have the capability of operation either in parallel with the grid or in islanded mode. Developments in power electronics have demonstrated that switching between modes is now technically feasible. Use of a DG system for both baseload power and as a backup supply would open the market significantly. It does however raise some safety issues. In the UK it is only possible to start operation in island mode once the entire site has been isolated from the utility grid.

Political Factors

In general, deregulation and liberalisation of electricity markets strongly favours smaller scale projects such as DG[74] because it frees the industry to recreate itself along competitive lines. In particular it allows customer choice and access (for example, to distribution grids) for new participants. The planning, design, approval, building and commissioning of large scale generating plant can require more than a decade and an impressive capital outlay to achieve[75]. Market-driven investment in new capacity additions will favour smaller projects that are on-line quickly and with lower total investment. Such projects can pay back and earn profit after only a few years, minimising the financial risk of individual projects and, for large investors, dispersing risk amongst a portfolio of projects.

Since the general nature of the electricity market affects the outlook for DG, it is pertinent to review the current state. Since many emerging technologies are suitable for fuelling by natural gas, the nature of the gas market is also relevant. The UK electricity and gas markets are substantially deregulated and liberalised. The process now is more one of fine-tuning the marketplace. The US and Europe are lagging behind the UK. Restructuring of the US electricity industry to allow competition is well underway, supported by both federal and state actions[76,77]. However, many states are currently at an early stage[78]. In Europe, whilst there is a high degree of liberalisation within national borders in a few cases (UK, Germany, Scandinavian countries), this is largely not the case between member states. Directives are now in place to open the markets for electricity[79] and gas[80]. The directives allow for the gradual opening of markets to 33% by 2003 and 2008 for electricity and gas respectively. In fact, many member states have already achieved or are planning ahead of these requirements[81]. Overall, in the geographical areas of interest, the market environment can be expected to increasingly favour small-scale generation over at least the next decade.

An issue, which has been contentious in the US for several years, is that of stranded assets resulting from restructuring for competition[77]. Estimates for stranded costs reach as high as $500m[78]. Many states are dealing with this issue by imposing charges in one form or another. If such charges are levied on DG, the financial impact on some DG projects will mean that they will be stillborn. This has led some to call for DG to be exempt from 'transition charges'[45]. Thus, it is uncertain whether a real regulatory barrier to DG will exist in many states for a number of critical early years unless policy-makers embrace the need for DG to receive positive discrimination.

Most developing technologies face a familiar 'Catch-22' dilemma: capital costs must be reduced to enter the market, but this requires mass production, not available until market entry has already been achieved. Developing DG technologies are no exception. This puts the outlook for DG substantially in the hands of the regulators and policy makers, people with the power to influence the market by manipulating market barriers and drivers. In the UK, DG based on renewables has received support in this way for a number of years via the 'Non-Fossil Fuel Obligation' (NFFO) and 'Scottish Renewables Obligation' (SRO) instruments[1]. Targets are for 5% generation from renewable sources by 2003 and 10% by 2010. CHP has also been actively supported with the government target having been 5GW of installed capacity by 2000. Renewables have received support in the EU also over the past decade[82]. CHP has been promoted since 1974 with various legislative measures[83]. The US also targets both CHP and renewables via its Office of Industrial Technologies CHP initiative[84] and Office of Energy Efficiency and Renewable Energy[85] (for example, the DoE target of 5% generation from wind turbines by 2020).

Initiatives such as those given above are set to continue into the medium-term future, driven by the need to control CO_2 emissions. The UK has recently extended its CHP target to 10GW by 2010[1]. Europe is also looking to the year 2010 with an 18% target for electricity generated by CHP[86]. However for power-only, fossil-fuelled DG, government support is currently largely confined to developmental support for the technologies themselves rather than promoting deployment against government targets. The degree by which governments embrace these technologies as contributors to environmental objectives will be a major wildcard.

Supply reliability

Electricity consumption in OECD-type countries is characterised by an increasing importance of supply to sensitive electronic equipment, such as computers. These are increasingly being relied upon for high-value manufacturing processes and commercial operations. Since some DG technologies are capable of very stable voltage characteristics and/or supply reliability, interest has been expressed in their use as premium power supplies and in uninterruptible power supplies.

Many DG technologies are seen as offering the promise of fewer forced or planned outages than conventional technologies. This is in part due qualities intrinsic to the technologies and part due to the fact that the leading technologies are fuelled by natural gas, delivered via a reliable underground pipeline system[87]. DG technologies are typically capable of availability factors of 90-97%[88,89] compared to 77-82%[90] for the epitome of the central model – plant of 1GW+. As a result some users are already turning to distributed technologies as reliable power sources, in some cases despite current high costs. Examples include a 1MW phosphoric acid fuel cell system at the Anchorage Post Office Alaska[91] and several hundred MW of diesel engine peaking plant used by ComEd in the Chicago area[92].

The US has seen significant problems with supply reliability in recent years. Insufficient capacity at peak periods has resulted in low voltages or complete blackouts, equipment failures and excessive electricity prices at peak periods[75]. 20% of insurance claims and $26 billion/year in losses have been reported to be due to power outages in the US[93]. Consequently, the reliability of electricity supply is increasingly becoming an issue for many large commercial and industrial users; for example, where the high value of operations mean power outages are costly. These are often businesses with critical computer databases such as supermarkets, banks, etc or businesses with high-value power-dependent operations. One quarter of US businesses have declared a willingness to pay a 10-20% cost premium to solve the problem of sporadic power outages[94], motivated by the large financial losses that can accompany a power outage (one manufacturer claimed a power cut this year cost them $3m per hour in lost production[95]).

In the UK, the situation is rather less encouraging (as a fillip to DG). Apart from major storm related disruptions to supplies in the Scotland and the North of England in 1998, supply security has been generally good[96]. Outages average only 0.78 interruptions per customer per year (81 minutes/year)[97], the situation having generally improved since privatisation[98]. As a result, customer attention is not focused on supply security. A MORI pole[99] of UK business and domestic customers found that only 7% of businesses were dissatisfied with the reliability of their electricity supply and were prepared to spend only a 2.5% premium to improve standards (c.f. correspondingly high figures above for the US).

Such considerations are likely to persist in the US for some time yet as it struggles to keep pace with faster than expected demand growth[100] against the background of electricity industry reform and deregulation. Customer attitudes toward supply reliability are therefore set to continue favouring DG. However, as a result of the above considerations, DG is unlikely to receive such widespread attention as secure power sources in the UK. This situation is likely to persist, given that OFGEM is committed to continuous tightening of distribution and transmission standards[101].

Grid Support

Network operators generally cite the *strategic* placement of embedded generation as a major advantage of DG for a number of reasons, all of which relate to the impact of DG on the distribution network.

- The deferral of T&D upgrades is frequently quoted as a major attraction of DG. Costs for extending cables are large ($120k-$3.3m per mile in US[102], £16k-£160k per mile in UK[70], not including wayleaving costs). In the UK, of the order of 1MW per thousand customers could be embedded without requiring distribution grid reinforcement[103] (around 400% of what is currently connected). However, this is true only if capacity matches local demand. Network operators already find it difficult to add capacity without grid upgrade. For example, Norweb are unable to accommodate any generation at all on the West coast of Cumbria[103].
- The image of overhead power cables is generally poor. The major concern here is fear over the health effects of electromagnetic fields (EMF)[104]. Whilst EMF have been implicated in causing ill health, the matter is still open to debate and may well remain so indefinitely.
- Increased difficulty in securing wayleaves for grid extensions. Wayleaving can be a lengthy, costly and delicate matter[70]. Usually the scope is limited by the need to avoid relatively problematic private land.
- Embedded generation is often viewed as enhancing the performance of the network. However, the scope for voltage and current support to the network appears to be somewhat limited[70].

The Environment

Possibly the highest profile environmental issue pertaining to the electricity industry is that of climate change. One of the most significant climate change events of recent years was an agreement of quantified national emissions targets in 1997, the so-called Kyoto Protocol[105]. Under the Kyoto Protocol, EU and US are committed to lowering anthropogenic emissions of the carbon dioxide equivalents of a 'basket' of six greenhouse gases to 8% and 7% of their 1990 levels respectively, this to be achieved by the period 2008-2012. The UK's target has been set within the EU to be a 12.5% reduction[106]. However, the most significant emission from the electricity industry as far as climate change is concerned is carbon dioxide (CO_2). In this respect, the UK also has a more stringent goal of a 20% reduction below 1990 levels by 2010[107].

The issue of climate change will impact significantly on the prospects for DG as governments act to fulfill their obligations under the Kyoto Protocol, because many current or emerging DG technologies offer a means to use fossil fuels more efficiently, automatically emitting less CO_2 (renewable generation of course emits zero CO_2). This efficiency advantage is boosted further by reduction of T&D electrical line losses. These losses are largest in developing nations where figures above 20% are not uncommon, but can be large even in OECD countries. In the US, 8-10% of gross electrical generation can be lost between central plant and user[46], 8% in the UK[108]. New T&D technology may reduce these figures; DG would virtually eliminate them.

Emissions of pollutants from the most potent large-scale competition to DG, probably the combined cycle gas turbine (CCGT), effectively represent targets for DG. A DG technology must have lower emissions in order to qualify as an environmentally beneficial alternative to central-power. Most DG technology compares favourably with CCGT in this respect.

Environmental issues are an important factor controlling the prospects for DG and will continue to be so provided the environment stays high on the agenda of governments. The Kyoto agreement will enhance the prospects for DG, but it is the environmental initiatives of the future that will shape the prospects for many DG technologies. These are highly uncertain and unpredictable.

Electricity Price

The future market price of power-by-wire will affect the outlook for DG substantially. The opportunity for shelter from high volatility in electricity prices is frequently regarded as a positive driver for DG[45,46]. This is particularly true in the US, where power costs not only vary wildly on a monthly timescale[109], but can also vary hourly depending on demand and availability of generators.

As mentioned above, deregulation and liberalisation of electricity markets opens doors for DG, but will almost inevitably lower electricity prices. This highlights the challenge for many DG technologies, which are starting from an economically weak position and may suffer if the needs of DG are not accommodated in liberalising electricity markets (already CHP advocates are reporting problems due to markets opening in Europe[110]). It also highlights the uncertainty in future DG markets that will depend on prices, which will be determined by a complex interplay of unique political events, economic growth, social decisions and various other price pressures, all fluctuating unpredictably on local and global scales.

Customer Acceptance

The progress of DG will be affected by the rate that companies with a vested interest accept DG. The concept of DG has built up considerable momentum and this has shown strongly in the sheer volume of positive information discovered in the literature and on the Internet for this review. Nevertheless, acceptance is far from universal, and negative attitudes exist. ADL poled electric distribution companies in the US for their concerns over DG[51]. The possibility of negative impacts on system reliability and utility worker safety were their greatest worries. Similar concerns exist in the UK where suppliers face an obligation to supply via condition 10 of the Public Electricity Supplier licence[111] and where safety is at the top of the Network Operator's agenda when dealing with a connection[112].

Negative attitudes towards DG extend beyond operational concerns. Some electric utilities are opposed to DG because it threatens central power[75,87], resulting in the loss of some of their largest and most consistent customers to on-site power. Electricity suppliers will generally lose revenue when the generation is located customer-side of the meter[113]. As a result, incumbent utilities often apparently engage in discriminatory behaviour to obstruct DG. For example, some utilities have traditionally overpriced back connections to the grid. Such behaviour will undoubtedly slow market growth, but is unlikely to prevent it in the long term, particularly if policy makers act to remove such barriers.

By contrast, many utilities are positioning themselves to be key players in distributed power[75,87]. For example, the active management of small-scale plant located on customer premises. Some see this as a key factor in the development of a large DG business[114].

The power-by-wire model is ingrained in the majority of electricity customers also and will not change easily. This is one of the factors that ensure that, irrespective of major technical breakthroughs, DG will probably not take the market by storm, but will progress steadily. For example, for on-site users, a strong case (usually economic) will be needed to broaden management focus from core business to what will frequently mean participation in the power generation business.

3.2.2 Biogas-Fuelled Distributed Generation

We have seen in the previous section that DG brings with it a number of drivers, which have caused the concept to gain considerable momentum. The demand for DG will extend to the biogas-fuelled units, but the drivers already mentioned will be subtly changed in emphasis. For example, many of the highest-value businesses tend to be those manufacturing high technology or those critically dependent on sensitive electronic equipment, such as banks and large supermarkets. These will tend not to have a ready supply of easily digestible waste material. Therefore, the need for security of supply will not operate as strongly for BDG applications until the development of a biogas supply infrastructure widens the BDG market. Unfortunately the barriers to DG will also tend to translate over to sites where biogas is available. For example, these sites will tend to be in a rural setting where grid interconnection issues will tend to be more severe.

Overall, biogas applications will undoubtedly benefit from the influence of the growing wider market for DG. However, BDG brings with it a further set of market drivers and barriers, again related mostly to the advantages and disadvantages of the concept. These are discussed in this section and shown in Figure 9.

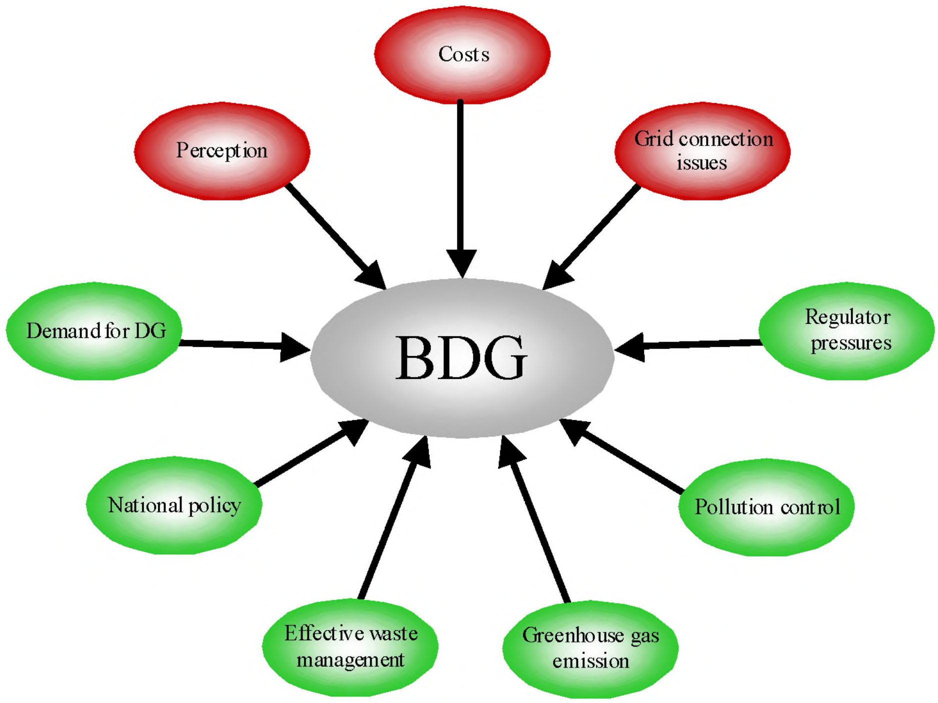


Figure 9. Biogas-Fuelled Distributed Generation Market Drivers (Green) and Barriers (Red)

Greenhouse Gas Emission Control

The dominant driver for biogas production and BDG is the environment, particularly the need to control greenhouse gas emission as discussed in Section 3.2.1. The highest-profile greenhouse gas is carbon dioxide, but methane is a far more potent greenhouse gas in equivalent amounts. The Intergovernmental Panel on Climate Change is constantly re-evaluating the relative potential of various gases as scientific understanding of the global warming phenomenon evolves. In recent years methane has been considered to have around twenty times the global warming potential of carbon dioxide[163]. As a result, the need to control methane emissions as well as displace carbon dioxide produced by the burning of fossil fuels will be a strong driver for biogas schemes and BDG. This driver is likely to persist throughout well beyond the period to 2020 and will likely increasingly favour BDG as the environment moves up the political agenda.

This driver will particularly operate to favour BDG utilising landfill gas. Landfill emissions represent a major source of methane emissions to the atmosphere[143]. Partly because AD in landfill sites takes place at a relatively low temperature, methane emissions from large modern landfills can continue for 15-30 years[16] and represent more than 100m^3 of biogas per tonne of MSW[133]. In the UK approximately 8 million tonnes of organic waste are produced annually. Historically 85% of UK waste has been deposited in landfill sites. The importance of controlling these emissions is highlighted by the fact that this gas is equivalent to 14% of the carbon dioxide produced from generating electricity from natural gas in the UK.

Pollution Control

In addition to issues of greenhouse gas emission, there are a number of environmental benefits of biogas schemes, which will act to drive these schemes and therefore BDG. In particular, AD facilitates a reduction of pollution through effective waste management. Farm-generated slurries have a high biological oxygen demand (BOD), which can result in pollution of ground water. Storage of materials or application of raw material to land results in odour nuisances for people living close to farms, due to uncontrolled anaerobic digestion resulting in generation of volatile fatty acids and organo-sulphur compounds. Digesting waste farm material can reduce odour by up to 97%[162] and also reduces BOD. Furthermore, use of liquor as fertiliser can result in reduced nitrate pollution of water courses, because more effective nutrient application leads to less run-off from fields. However, liquor is in one respect less efficient than mineral fertilisers, because a portion of its nitrogen content must be mineralised by soil bacteria before it is available for the crop[155].

The Political Agenda

Heightened concern about climate change has stimulated action plans worldwide. The NFFO and SRO schemes have supported the deployment of BDG in the UK. Continued support will be through a new Renewables Obligation[130]. Government targets are for 5% of the UK electricity requirements to be met by renewables by 2003 and 10% by 2010[131]. The government's definition of renewables includes biomass sources. An important economic instrument, which will act to support BDG in the UK is exemption from the Climate Change Levy (0.43p/kWh) for electricity generated from renewables[144]. This will significantly affect BDG economics.

A further economic instrument in the UK that affects the economics of BDG from landfill gas is the landfill tax[170], which means that organic waste has a negative value for the business sector. Whilst this encourages extraction of value from the waste, e.g. by power generation, the EC Landfill Directive[171] requires significant cuts in the amount of biodegradable municipal waste landfilled. This will undoubtedly slow the growth of landfill based BDG, but may mean that local authorities may in the future opt to send a portion of the waste to existing digestion plants for co-digestion or set up new AD plants.

In the US, BDG is favoured at both federal and state level[122,141]. The DoE supports BDG via its Small Modular Biopower Initiative. Activities include technology development, feasibility studies and technology deployment[119,120]. Federal Restructuring of the US electricity industry is adding an extra incentive for renewable energy via the provision of 'Renewable energy Standards': for example, Texas requires more than 2000MW of renewable power by 2009 and 400MW by 2002, landfill projects already receiving the benefit[122].

Throughout the nineties, the EU has adopted a portfolio of policies that have been major driver to the deployment of renewables, including biogas[82,164]. These have been both at national and EU level. BDG received a major boost in November 1997, when the European Commission adopted a white paper[128], which set out an action plan to achieve a doubling of renewables' share of the European energy supply from 6% to 12% by 2010. This document recognised the need to promote biogas production. A detailed plan was put forward in the EU's 'Campaign for Take-Off' and called for the promotion of 1GW of biogas installations (800MW large-scale and 200MW small-scale) by 2010. The EU ALTENER programme will support this campaign, developing new market and financial instruments, disseminating information, etc[132].

Overall, there are national targets for deployment of renewable energy that augur well for BDG. The outlook for BDG will depend on substantially on whether these are met and how they are extended in the future.

Regulatory Pressures

Driven by response to pollution incidents and the high position of the environment on the political agenda, there are increasing regulatory and public pressures on farmers and others to ensure that residues are dealt with in ways which are environmentally sound, and carry less risk to human and animal health than traditional methods[160]. Properly managed AD schemes will help farmers meet these pressures.

Grid Connection Issues

There is a significant demand for heat in the UK. Many sites that can produce biogas will not have a significant demand for power. If the power cannot be used on site then it has to be exported. Unless the site is operating on a net-metered basis, the value of exported power will be less than that of the power used locally. The net-metering issues are currently being debated but net-metered energy services agreements are becoming available.

Costs

The capital cost of AD technology is a significant barrier to BDG. In the UK, a 300m^3 digester (capable of powering a 200kW ICE), with a boiler and separator, costs around £105k-£300k[154]. This would add a further £500/kW-£1500/kW to a generation project, enough to make this look unattractive. This highlights the importance of the market/savings for additional products, together with integration of the project with other site activities.

In fact, the economic case for BDG projects is exceptionally complex to analyse. At a simple level, biogas could be viewed as a free fuel, being the by-product of waste treatment, thus greatly boosting the attractiveness of certain DG technologies. This may be the case in instances where DG is retrofitted to facilities already producing biogas, such as in landfills. In new schemes, most users will consider the full lifecycle cost of the whole scheme. In farm-based AD, this may include capital and operating costs of digester, generator and associated facilities such as fibre separator and composting equipment; electricity savings and savings on the purchase of synthetic fertiliser; and revenue from sales of electricity, fertiliser and fibre products.

A cost benefit analysis for this type of scheme is given in reference 154 and highlights several of the issues. This study confirmed the view that the farm-based AD is relatively unattractive economically in the UK. The generation of electricity and sales of fibre products were necessary in order to obtain meaningful payback periods. Significantly, the attractiveness increased markedly when the value of environmental benefits was included, payback periods tumbling. As with DG then, reconciliation of the benefits received from BDG with the interest group bearing the costs, will be a hurdle that will need to be overcome in order for large markets.

Control of Pathogens

A significant driving benefit for AD is the opportunity for reducing pathogens in wastes (particularly manures), breaking the cycle of infection and re-infection. The increasing emphasis within the EU and elsewhere on the use and recycling of organic wastes means that management and disposal of such waste frequently results in it being spread on farmland. Therefore, considerable opportunity exists for the spread of human, plant and animal disease pathogens[157]. Facilities operating BDG schemes on digester gas will be no exception. Indeed full utilisation of treated effluent is essential to the economics of such schemes.

Anaerobic digestion of animal manures is known to reduce pathogens, partly due to the anaerobic conditions and partly due to the high temperatures involved. Hence, the thermophilic process is particularly effective, both conditions being present simultaneously. Here, significant expertise exists in Denmark, where centralised plant are emphasised. Danish research has indicated a four order of magnitude reduction in particular pathogens from one-hour thermophilic digestion[162].

Past Experience

Set against the positive environmental drivers for AD is the fact that significant problems have been experienced in the past[156]. Problems that have been experienced include an inability to maintain a mesophilic temperature during the winter months, pipe blockages, digester pH instability and equipment failures. The resulting failure rate for AD projects is alarming; of the 45 on-site units installed in the UK between 1970 and 1997, 20 had ceased operation by 1997. Whilst technical problems may be easily solved, perceived risk in utilising a new approach inevitably endures. Problems such as these are really part of the wider issues of public awareness, perception and attitude. These issues will need to be addressed before large markets can occur, e.g. fostering awareness of availability and acceptability of fibre products[154].

3.3 Market Sizes

3.3.1 Distributed Generation

Around 54GW of CHP is installed in the US, representing 10% of power generation[145]. Not all of this will be DG, some being at larger scale. A.D. Little estimates that there is more than 60GW of DG in North America, in the form of engine and turbine technology of less than 20MW capacity[51]. This market is growing at a rate of around 9%/year and equates to 8.7% of total generating capacity. Below 10MW, the fossil-fuelled market is mostly served by engine-based technology; above this power, turbines dominate[146]. Given that distributed renewable generation amounts to around 12GW of US installed capacity[147], the total for DG technologies probably amounts to around 72GW (around 8% of the total).

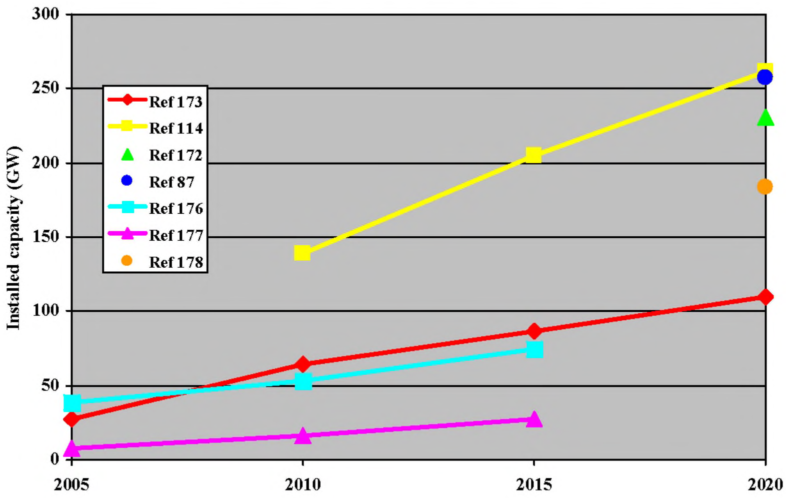
In the UK, information on CHP and renewables is published annually by the DTI[1]. Combining this with information from elsewhere[138] suggests that there is at least 3.5GW of DG (<50MW capacity) in the UK (around 5% of the total), growing strongly due to increasing markets for CHP and renewables.

Complete revolution of the power generation industry would represent an upper limit for DG and spell the end for large-scale power. Some advocates have made this prediction. They may even be right, but barriers to DG are real, formidable and will persist; some companies will resist rapid market revolution, which would otherwise strand assets; and time is required for technology to evolve to the point where it is truly competitive. Unless there is a major step change in the market environment, it is far more likely that DG will maintain a relatively minor contribution in OECD-type countries, and will make steady inroads into the market over the timescale considered.

Nevertheless, impressive growth has been achieved in some cases, supported by national policy. For example, in the Netherlands DG represents around 30% of installed capacity and 13% of production, CHP (distributed and large scale) having quadrupled in one decade to represent 40% of installed capacity[137].

The US market is discussed most in the literature (see Figure 10). In many cases, for the reasons mentioned above, figures have not been extracted unchanged from the literature, but have been recalculated based on various reasonable assumptions to make them more comparable. Figure 10 shows a broad spread of expectation spanning a factor of about 7 in 2020. But this is really not that broad when it is considered that markets are forecast 20 years into the future and DG definitions have varied between sources.

Figure 10. Comparison of US DG Market Size Predictions



References 114, 172 and 173 are from the same analysts and show a current willingness to acknowledge higher penetration of DG than that shown 5 years ago. This typifies the generally higher expectation for DG that has developed as DG has gained momentum.

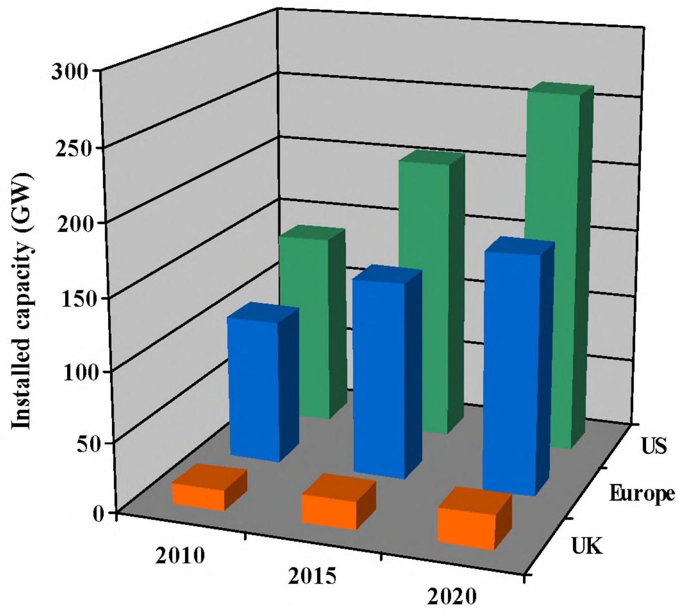
The lower end of the prediction range (~40GW-260GW), implied by Figure 10, may be too pessimistic by 2020. The DOE intends doubling CHP capacity by 2010, a goal that should be easily achievable. Future DG technology is such that it could render a significant fraction of the 169000 commercial sites of 100kW-10MW, totalling 82.8GW[148], commercially viable along with some of that portion of the 88GW of remaining industrial CHP potential that is relatively small-scale. Add DOE targets of 25GW for renewables[149] and figures as low as 40GW should easily be achievable long before 2020, and probably before 2010 even with modest success at converting potential to real projects and without any of the large fossil-fuelled, power-only market that new technologies are expected to create. Indeed *current* DG capacity is reported to be in excess of 40GW[51].

The lower figures are evidently generally only smaller scale DG or possibly omit some applications. The highest figures in Figure 10 are from EscoVale[114]. Interestingly, many would not regard even these as overly optimistic, representing as they do, around 21% of US total generation in 2020. EscoVale have poled informed opinion, finding that 25% was a typically offered as a global figure (c.f. 17% in EscoVale's central forecast). On balance, the higher figures seem credible.

DG is seen by EscoVale as penetrating less of the European market than the US market, representing 19% of total European generation in 2020. This may be slightly generous. The CHP sector is currently reporting its economic case has suffered as liberalisation proceeds[110]. If this is so, DG will be slowed initially or delayed, and the predicted growth will be pushed further into the future.

No suitable market projections for the UK have been located in the literature. Instead, based on broad similarity of many issues concerning DG between the future European and UK markets, the European figures can been scaled back according to the relative sizes of the UK and European electricity generation markets. This approach estimates around 24GW of installed DG capacity by 2020. Adding figures of 171GW and 261GW for Europe and the US respectively gives around 460GW as a total for the three geographical regions of interest by 2020. The predicted markets are given in Figure 11.

Figure 11. Predicted DG Market Sizes



3.3.2 Biogas Distributed Generation

Market Indicators

The markets for both renewable energy and waste management are both in significant growth phases at present. For example, the value of the global renewable energy market is predicted to be $640bn by 2010, which is approximately double its current value. In the EU, the value of the renewable energy market should increase to 30bn by 2003 and to 84bn by 2010.

The recent financial performance of biogas plant manufacturers and suppliers supports the view that the market is in a growth phase. Other renewable energy companies, particularly in the wind turbine sector, have also showed continued growth in 2001 of up to 200%. Market performance of renewable energy stocks indicates that the overall market is less satisfactory. Only two of the top 25 renewable energy stocks increased in value in September 2001 with some prices falling by more than 50%. Three renewable energy and environmental technologies indices (Impax ET50, Renewable Energy Tracker and MSCI World Index) all fell in September by between 16% and 24%. Although September 2001 was an exceptional month for all financial markets, the overall trend for the last 12 months, has shown a steady fall in value.

Market Size

Evaluation of market sizes for biogas applications is somewhat difficult as there are variations on how nations record their data. For example, some countries include power generation from landfill gas and from sewage gas in their national statistics; others do not. For the purposes of this report, market analysis data will consider only the UK scenario in detail.

Agricultural wastes are already utilised for fertilizers etc in the UK, however legislation is restricting this use. Chicken litter is the ideal feedstock for AD as it gives the highest yield of biogas per unit mass of waste, however several of the major poultry farms already supply waste to centralised plant for combustion. The three chicken litter fuelled power stations account for approximately 20% of the UK production. The potential feedstocks are now limited to smaller farms. The outbreak of foot and mouth disease in the UK in the spring of 2001 will have a significant impact on the populations of livestock producing suitable wastes for AD. Waste slurries could have been reduced by up to 25%. It is unlikely that these populations will return to original levels as there are EU targets to reduce UK agricultural output. A realistic assessment for the market potential for biogas from AD of agricultural waste is between 2 and 4TWh (approximately ½% to 1% of current demand). This would probably equate to around $1GW_e$ of installed power generation capacity.

There is currently only a small amount of electricity generation from landfill gas. In the UK, use of landfill gas in this way has been increasing in recent years under the NFFO. At 2000, UK generating capacity stood at 383MW[1], only around 0.4% of the total. This compares with figures of 760MW (0.13% of capacity) and 800MW (0.1%) for the EU and North American capacity respectively. There has been little expansion of this market outside of the NFFO arrangements, which would indicate that the market will not expand without external financial incentives. The current market penetration of approximately 20% suggests that there is a significant market that can still be exploited. However if the market is not attractive at the larger end of the scale without incentives, then the potential market for microturbines and small scale CHP is likely to be small. High installation costs due to the requirement for gas processing equipment and unproven technology are likely to suppress market penetration in the short term. In the longer term as gas prices increase and the technology becomes more widely accepted, there is the possibility that this potential could be exploited on a commercial basis.

Power generation from landfill gas will almost certainly increase significantly in the coming years as the main market driver (the need to control landfill gas emissions) takes greater hold. In Europe, this growth is unlikely to continue into the longer term. For example, in the UK the size of the landfill gas resource has increased historically at 10%/year[133], but the EC Landfill Gas Directive will certainly curb this. The market potentially addressable by BDG could be around 4TWh, equating to around $1GW_e$.

Sewage gas utilisation in the UK is unlikely to increase significantly and the resource is relatively small. Over $90MW_e$ capacity is currently installed with 35% going in under NFFO agreements. Although there is little potential to expand this mature market, some plant will be reaching the end of its operational life. As the rate refurbishment increases, there will be a requirement for microturbine equipment. Although the market in the UK is limited, recent news articles have indicated that there is significant potential overseas. In the USA there are 16,000 existing wastewater treatment sites that have been identified to utilise biogas for power generation. Microturbines are beginning to be exploited in this area in the USA.

Overall, there is a significant biogas resource in the UK potentially available for small-scale power generation. A breakdown of this estimated resource is offered in Table 4. The table indicates that the total potential for BDG in the UK is around 11TWh/yr. This probably equates to around $3GW_e$.

Table 4. Biogas potential from UK waste in the UK.

Application		Potential (TWh/yr)
AD	Agricultural & process waste	8.3
	Sewage	0.09
Landfill		3

NB. This table does not include the potential from energy crops, which would allow capacity to be increased. Also, it does not take account the installed capacity and alternative uses of the feedstocks. The data are also based on figures collated prior to the UK outbreak of foot and mouth disease, which has had a significant impact on the populations of cattle and pigs.

The likely future installed capacity will depend on the conversion of potential into real projects. Many sites that can produce biogas will not have a significant demand for power or will have a demand largely for heat with relatively little power. If the power cannot be used on site then it has to be exported. Unless the site is operating on a net-metered basis, the value of exported power will be less than that of the power used locally. The Net-metering issues are currently being debated but net-metered energy services agreements are becoming available. In some cases users will elect to use biogas for direct heating in suitable boilers. However the value of heat is less than that of power and the costs of the digester plant usually make biogas heating systems financially unattractive, especially when compared to other renewable fuel heating systems, such as woodchip heaters, or conventional fossil fuel systems. This market sector is therefore likely to be small.

As mentioned above, market development is near complete for sewage gas, future sales of generators being largely confined to the replacement market. The prospects for development of landfill projects are also bright. Given the market conditions, it is not unreasonable to suppose that utilisation of this resource will approach 50% by 2020. The market for BDG operating on digester gas has considerable potential, but is little developed. Given the net effect of the barriers and drivers discussed in section 3.2.2 is unlikely to result in a highly developed market, perhaps only 30%. A reasonable estimate for installed BDG capacity by 2020 would therefore be around 1.1GW$_e$ (c.f. current installed capacity of around 470MW), perhaps generating around 4.5TWhr/annum. This would represent around 1% of total generating capacity and according to the market forecast in Section 3.3.1, around 5% of DG.

This figure is of the same order as literature estimates. The potential for renewables to contribute to the World's energy needs is widely acknowledged. A variety of studies have investigated the development of future markets using scenario modelling and are reviewed in reference 16. These see a significant expansion of renewables with biomass being the dominant renewable fuelstock in the long term. Reference 16 suggests that in the UK, electricity generation from biogas (from landfill gas and sewage gas) could increase over the period 2000-2025 by a factor of 2-3 depending on scenario, perhaps reaching 9TWh/year.

3.3.3 Outlook for Biogas-Fuelled Microturbines

The scale of microturbines is not ideal for landfill gas application, which demands MW+ generators. Whilst significant numbers of microturbines have been sold to this application, e.g. the 50-unit installation at a Los Angeles site[31], it is unlikely that microturbines would be the technology of choice in the face of competition from equally modular, larger-scale technologies with equal or better efficiencies and emissions. Fuel cells and larger turbine technologies will likely predominate by 2020. Nevertheless, in the near term, further sales to this application are likely.

As a pure power generation system or energy generation system, the economics for microturbine based biogas applications are not good. As a purely cost cutting measure based on reduction of energy costs, small scale power or cogeneration is likely to be unattractive. It will only become attractive if an existing digester is in place or where the site energy needs are increasing the installation of cogeneration equipment can be offset against the upgrade costs. When integrated into a total energy solution the economics of the overall system can make the installation economically attractive. This is becoming particularly important as financial incentives for reduced environmental impact become commonplace and significant economic drivers. There are several variables as there are numerous potential outputs from an integrated package. If the installation is part of a waste-management installation, the waste management element of the overall revenue dominates the economics.

Overall, microturbines will compete reasonably well with other technologies in many cases. Arthur D. Little have assessed the market potential addressable by various technologies in the 25kW-1MW power band fuelled by wastes and biofuels[142]. They concluded that in a deregulated environment with aggressive R&D success, the microturbine market opportunity could account for around 23% of the opportunity for the whole sector to 2010. A figure of 35% applies to fuel cell/microturbine hybrids.

4. Demonstration Trial

4.1 Introduction

A biogas fuelled Capstone microturbine has been installed and tested in the UK in a programme that has been funded by Advantica, Transco, Capstone and The Department of Trade and Industry. As part of this project, field trial demonstrations of a biogas compatible microturbine have been conducted on two sites and in two different configurations.

The first site was part of the Hybrid Renewable Energy System owned by De Montfort University and located at their Caythorpe campus in Lincolnshire[179]. This site had a fully operational, continuous feed digester linked to a piston engine cogeneration system. In this trial, the microturbine used as a direct replacement for the piston engine. The microturbine was operated in a power only mode as it was not linked to a waste heat recovery unit.

The second trial was set up after the closure of the Caythorpe site. A study called the Integrated Research into Waste – Energy, Feedstocks and Residuals (IRW-EFR)[180] was being conducted by a joint venture between AMEC and The University of Liverpool. As part of the study, a 5-cell batch digester linked to a research greenhouse has been constructed on an existing nursery in the Wirral (Figure 12).

Figure 12: IRW-EFR demonstration site

The construction project was part funded by the European Union under Agenda 21. In this trial the microturbine based cogeneration system was installed with the exhaust linked to a waste heat recovery unit. The recovered heat was utilised to heat the digester cells, the main building and the excess heat used by the adjacent greenhouses. Power is used locally on the site with the option to export any excess to the grid. The flue gases from the microturbine will also be utilised for carbon dioxide enrichment and low grade heating within the greenhouses, however this was not carried out during the trial.

4.2 Installation and Monitoring

There are three key differences between the two trial sites, which are the digester type, the microturbine installation and the flare configuration. The main difference is the digester. A single continuous feed digester was used at the first site whereas a 5-cell batch feed system was used at the second. The microturbine was installed with a filter acting as the water separator at the first site whereas a refrigeration dryer was used at the second. The microturbine was only linked to a waste heat recovery boiler at the second site. The flare stacks at the two sites were slightly different and at the first site there was no flare gas storage facility.

At both sites the power supply was linked to the local utility in accordance with the G59 connection regulations. Although the microturbine is equipped to isolate itself from the utility in the event of a grid failure or disturbance, a separate backup G59 compliant relay system was fitted. This simplified the installation process for the local utility. A breaker was also included to allow the turbine to be isolated from the grid and locked off.

The waste heat recovery boiler was not installed on the first test site and the exhaust was vented directly to atmosphere. At the Wirral site, the high-grade heat was recovered to produce hot water. The hot water system is linked to the main research building, the digester underfloor heating system and to the host site, which has a high heat demand. The split of heat demands is not known, however the heat load allows all the recovered heat to be utilised. There are plans to recover the low-grade heat in the exhaust in the main body of the greenhouse; however, this has not been implemented at this point as the operation under the potential range of operating conditions has not been fully tested.

The electrical installation used for both site installations provides back-up disconnection for under and over-voltage scenarios and for loss of mains. Additional relays were required to ensure compliance with the G59 connection regulations in the UK.

4.2.1 De Montfort University Installation

The figures below (figures 13 and 14) show the installation at the Caythorpe site. In the foreground is the gas storage bag, behind that is the top of the digester tank and in the background is the residue slurry storage. To the right is the shed in which the cogeneration systems were located. For the microturbine trial, the fuel compressor, microturbine and electrical connection equipment were all located in this area. The power from the turbine supplies the site and the adjacent offices and workshops.

Figure 13: DeMontfort University HRES Biogas Installation

Figure 14: DeMontfort University HRES anaerobic digester

4.2.2 AMEC IRW-EFR Installation

The Wirral test site (figure 15) is based around 5 digester cells seen on the right of the figure, each with a capacity of $100m^3$. The site is designed to be modular and flexible allowing the design to be applied to a range of sites. It is expected that the optimum size would use a 5x2 array of similarly sizes cells. At the trial site the cells are accessed on the northerly side of the building and a research greenhouse has been built with a southerly aspect. The cells are mainly underground to reduce thermal losses from the cell walls.

The top of the cell is at ground level and is easily accessed for filling and emptying. Each cell has a lightweight lid that can be removed by a single operator using the mobile crane. There is an underfloor heating to maintain the cell operating temperature. Two pumps can recirculate the liquid component in a cell to ensure mixing of the waste and transfer the liquor between cells when required. The liquid is taken from a drain on side of the cells and sprayed back in near the top. Biogas is taken from the cells and the H_2S is removed by a scrubber seen in the centre of the image then stored in a $20m^3$ gas bag, which is located in a lined Portakabin seen on the left of figure 15. When the gas bag is full, the cogeneration system is started, the gas is compressed and dried before entering the microturbine. The exhaust currently passes through the waste heat recovery boiler before exiting through the stack in the roof of the building.

Figure 15: IRW-EFR test site anaerobic digester cells

The microturbine installation is shown below (figure 16) with the heat exchanger. The exhaust heat is recovered to produce hot water at 80°C. The exhaust is then vented to the atmosphere and leaves the flue stack at around 100°C. There are plans to modify the exhaust to allow the low grade heat and the carbon dioxide enriched flue gas to be recovered. This would recover approximately 15kW of low grade heat and potentially allow all the CO_2 to be absorbed.

Figure 16: Microturbine cogeneration installation

Figure 17: Anaerobic digester cell with lid removed for filling

Cells are filled either by removing the lid (figure 17) and tipping waste in or by pumping slurry directly into the cell. As the addition of slurry does not require lid removal, this can be carried out at any stage of the digestion process.

Data measurement

Microturbine operational data is obtained using the CRMS monitoring software as supplied.
Analysis of the fuel gas at the Caythorpe site was carried out using Drager tubes GC at DeMontfort University with GC used for accurate analysis. The Wirral AMEC site is equipped with in-line systems for operational monitoring and with high accuracy mass spectrometry for occasional sampling. Other biogas measurement techniques are being developed and tested at the site and are used to confirm the data obtained with the main techniques, as these are being developed as research tools they are not use as part of the on-line monitoring system and the data obtained is not referred to in this report.

At both sites, the exhaust emissions data was collected using a Land Lancom Series II portable flue gas analyser.

4.3 Trial Results

4.3.1 DeMontfort University Trial

Digester Feedstock

The feedstock for the DeMontfort University trial was pig slurry from the adjacent farm. Pig slurry was supplied at a rate of up to 1.3tonne/day. Biogas used in the initial trials was produced from a purely from the animal slurry feedstock. Gas production rate during the trial was an average of 1.2m^3/hr. As the feedstock was fixed and the digester was in a period of steady state operation, the gas composition was stable with methane levels consistently in the range from 60% to 65%. Tests with mixed feedstocks of animal slurry and agricultural vegetable wastes using a range of types of vegetable matter have also been undertaken on this site prior to the microturbine trial.

Gas Composition and output

The gas composition was consistent during the trial as the digester was fully operational using a single waste stream.
A single sample indicated that the composition was

CH_4	62%
CO_2	33%
H_2S	100ppm
H_2O	5%

The ratio of methane to carbon dioxide entering the turbine would remain fixed, however the water content was variable as the storage system was located outside in an uninsulated black bag (figure 4). Gas temperatures could vary significantly from sub zero temperatures to over 50°C at different times of the year. Significant daily fluctuations in temperature could also be seen, which affects the dew point of the gas and hence the moisture content (as the gas is usually saturated at the point of production). As the trial was conducted over the early summer months, the gas temperature and moisture content tended to remain at the upper end of the expected range. The figure quoted is for the fuel in the storage bag, prior to compression, filtration and pressure reduction. Some moisture was removed during the fuel filtration stages and the actual water content of the fuel at the point of use is unknown.

Turbine Operational Data

The gas storage bag holds 50m^3 of biogas. This allows 2½ hours of operation at full power. The majority of tests were carried out under full power (30kWe) however some short runs under part load conditions (20kWe and 10kWe) were also conducted. Some test data from trials is given below. These data were obtained when the ambient temperature was 10.1°C the pressure was 100.1mbar and the relative humidity was 45%.

A small improvement in performance and efficiency would be expected over the benchmark ISO conditions, as they are more suitable for microturbine operation. Total operational time on biogas was 28hours with 700kWh of electrical power produced. No heat was recovered during the demonstration.

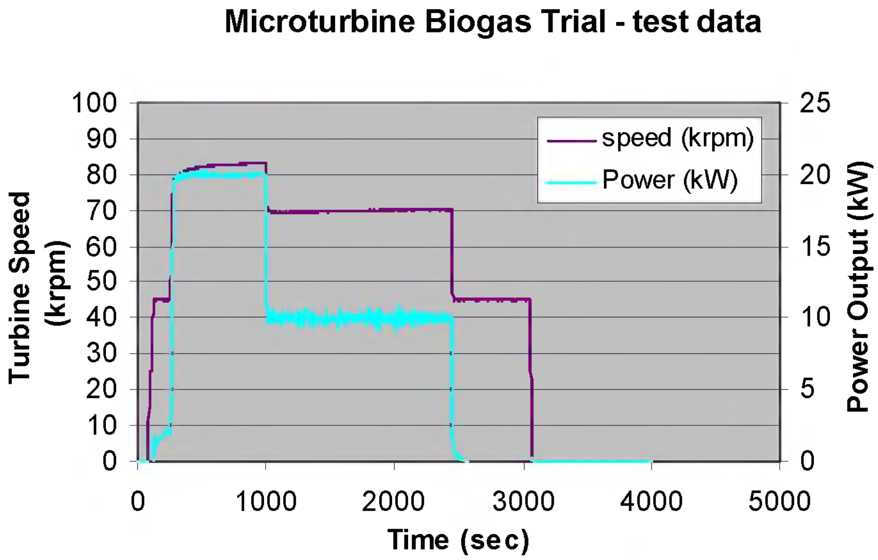


Figure 18: Speed and Power comparison

The above graph (figure 18) indicates how speed and power are related. At 20kWe the turbine speed was 83krpm and at 10kWe it was 70krpm. Earlier in the trial the full power was achieved at 91krpm, where the low temperature and high pressure conditions allowed maximum power to be achieved at a reduced speed.

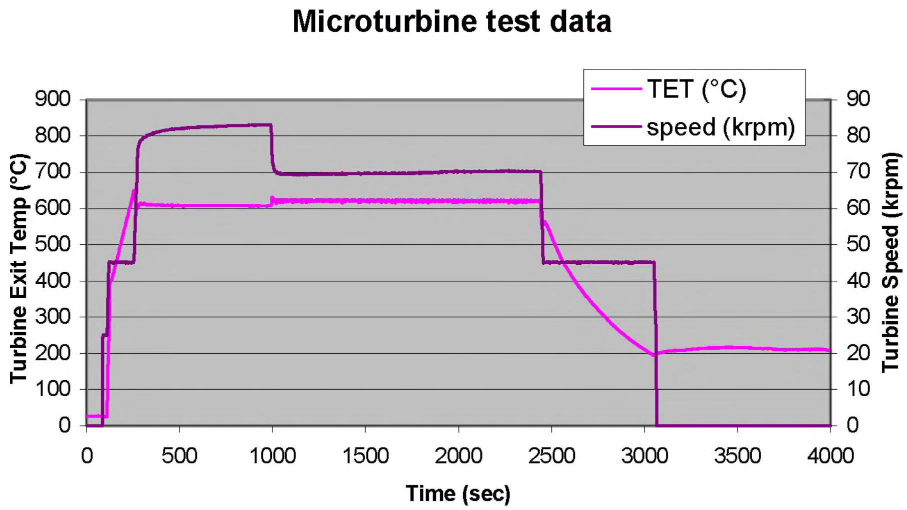


Figure 19: Microturbine Speed and TET relationship

Over the same period the speed and turbine exit temperature are compared above (figure 19). This indicates that under operational conditions the temperature is between 600°C and 620°C. The higher temperature is used at lower loads to maintain the efficiency levels. As the turbine is well insulated, the generator must operate as a motor to maintain speed and cooling to prevent thermal damage to the turbine or bearings.

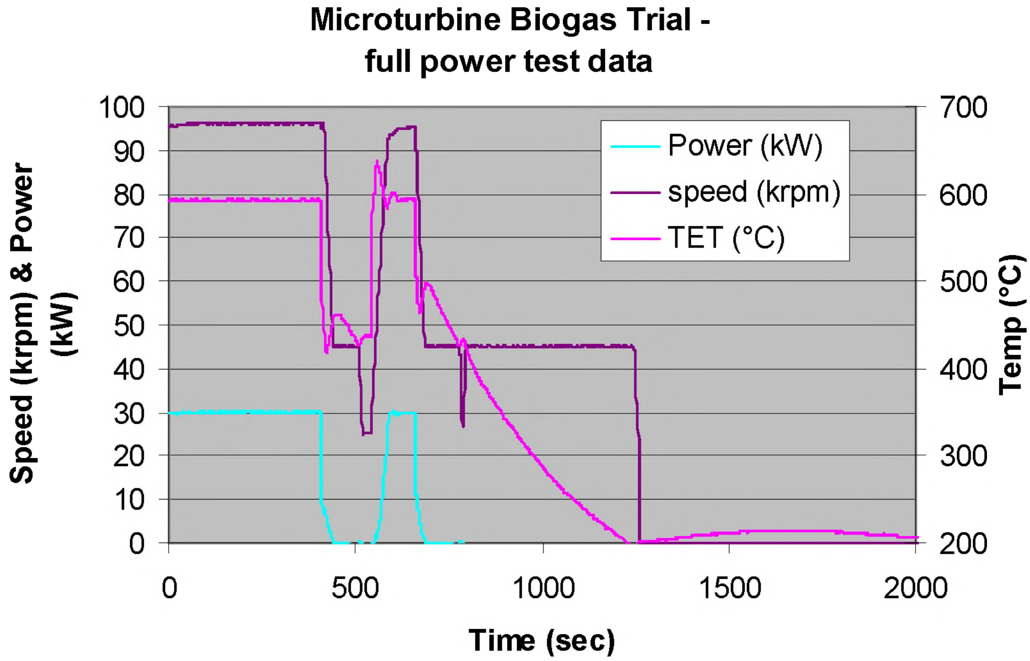


Figure 20: Microturbine Power Speed and TET relationship showing flameout.

The above graph (figure 20) shows data obtained from the end of a steady state full power tests in which there was a flame out due to variable gas quality. The test had run under steady state conditions for approximately 40 minutes. The data displayed, which covers the last 2000 seconds of the test, have been expanded. The events that these data show are the last 6 minutes of the test; a flameout shutdown; a successful restart; a second flameout; an unsuccessful restart than a cooldown. The flameout occurred after 410 seconds into this run. This caused the power to be disconnected immediately. At the point of the flameout the temperature also falls rapidly as the high mass flow of air cools the components. The speed is reduced from its operational level to the "warm down" level, which reduces the mass flow of air through the system. The rate of cooling is reduced when the air mass flow falls, which causes a slight rise in component temperature. After a short period in the warm down mode the turbine can be restarted. For a restart the speed is reduced and the ignition sequence is started. The unit was returned to full power in 88 seconds, which is less than the warm up period from a cold start. After re-ignition, there is a rapid rise in temperature followed by a rise in speed. At around 45krpm the generator is connected to the grid, although no power is being generated. From 45krpm to 96krpm the power is increased up to the maximum of 30kWe. The total down time taken to return to peak output after the flameout was 190 seconds.

As gas quality was variable at this point, there was a second flame out. When the restart was initiated the gas quality was such that the unit was unable to relight and so the unit went into a normal warm down mode. When component temperature reaches 200°C the unit goes into standby and the temperature rises for a short period due to lack of cooling air then falls slowly.

The biogas composition may be variable due to variations in the output from the digester or from stratification of the components whilst in storage. Biogas storage acts as a buffer to even out the digester output variations but can cause a decrease in gas quality during a run as the fuel is initially taken from the top of the bag. The turbine could accommodate slow variations in gas composition. Occasional transients in gas composition can sometimes be tolerated depending on the type of variation although they are more likely to cause operational problems than slow variations. Any transient is likely to cause combustion instability, which makes engine control more difficult. Combustion instability is easily detected audibly but sometimes difficult to detect using the turbine on-board monitoring system, which has a sampling rate of 2 seconds. The on-board diagnostics has a much higher sampling rate and can be used to indicate the cause of a shutdown. Variations in turbine speed, control temperature and throttle valve position are the main parameters that indicate that there is some variation of CV using the current system. A rapid increase in CV is unlikely to cause a shutdown through flame instability. It will only lead to a shutdown if the CV level is maintained, causing the control temperature to rise and the unit to shut down. A transient decrease in CV due to localised increase in CO_2 concentration is the cause of numerous flameouts. There is some evidence of short duration drops in temperature and increased throttle opening prior to some shutdowns. Several shutdowns were caused by flameouts particularly during the commissioning tests. Optimisation of the control parameters reduced the frequency of flameouts, however optimisation is a slow process and was not completed prior to the end of the trial. Emissions data indicate further modification of the control parameters is still required. Increasing the frequency of utilisation also reduced flame out frequency by reducing the residence time of the fuel in storage thus reducing the stratification of gases.

Emissions

The exhaust flue gas emissions were as follows.

CO	140ppm
SO_2	0ppm
O_2	18.5%
NO	1ppm
NO_2	0ppm
C_XH_X	0ppm
H_2S	5ppm
CO_2	2.8%

The high CO figure indicates that the combustion temperature is too low and that further optimisation of fuel settings is required to achieve optimum emissions performance. Optimisation is a slow, iterative process and a warm up period must be allowed after each adjustment. The figure quoted above was the lowest achieved during the trial. Total NO_x output of 1ppm is below the threshold for most analytical systems to measure accurately without resorting to heated sample lines etc. This figure is consistent with other exhaust gas analyses obtained from samples from tests run in the US. The H_2S level is at the bottom of the operational range of the analyser and should be considered to be less than 10ppm.

Trial Comments

The trial ran successfully until there was an intermittent fault in the electronics. The fault was not connected with the use on biogas in the trial. The on-board diagnostics indicated that the power quality was variable on the site and that both voltage and frequency were variable however they were within the G59 limits. The frequency of shutdowns increased until the unit became inoperable. The fault traced to the DPC, which had to be replaced. Although the design and control of the electronics should tolerate grid disturbances including large transients such as voltage spikes, it is unclear whether the quality of the power or a single transient event (such as a lightning strike) could cause the electronics to be damaged and cause the faults.
The replacement of the electronics took several weeks to rectify by which time the test facility at Caythorpe had been closed after restructuring by DeMontfort University. The second trial site was identified after the closure of the Caythorpe demonstration facility.

The trial of a microturbine as a replacement for a piston engine based cogeneration system has demonstrated that the two technologies operate in different modes. The turbine operates at a fixed power level. This requires a fixed heat rate into the turbine. In order to achieve this, the flow rate of the fuel must be controlled as the CV of the fuel varies. This has a consequential effect on the overall parasitic load on the system. In contrast, the piston engines operate on a fixed speed and fixed fuel flow rate. As the fuel CV falls, the output from the engine will reduce correspondingly. Outputs varied from 32 to 43kWe with gas consumption rates similar to that of the microturbine. There is no effect of the parasitic loads of the system, however, management of the output is more difficult. From an operational perspective the fixed output from the turbine would be the preferred option, however the improved efficiency of the reciprocating engine would give better financial performance. Also, maintenance requirements of reciprocating engines are generally increased as the engine oil becomes corrosive as it becomes contaminated with H_2S. Microturbines have the potential to have a low maintenance requirement, however most designs use oil-lubricated bearings. The oil-free design used by the Capstone ensures that there are no contamination issues, which is potentially a significant benefit to this design.

4.3.2 AMEC IRW – EFR Trial

Feedstock

The feedstocks in the operational digester cells were putrescible organic active waste mixtures from vegetable processing etc. (see figures 21 to 24). Sources of waste were usually food processing wastes and animal slurries; trials on municipal solid waste have also been started. Initial trials are operating using part-filled cells in order to increase the understanding of the processing requirements etc. These trials will not give an accurate indication of the volume and rate of biogas from full digester cells however they do indicate the likely volume of gas that could be produced and the time required to complete the process. Examples of vegetable waste material include tomatoes, peppers, melons, onionskins, citrus fruit and salads. Due to the large volumes required, most waste samples contained a mixture of the above in varying ratios Animal slurry was taken from a cattle farm and this was introduced to cells to initiate the bioreaction. When a cell is filled with fresh waste, the liquor from an active cell can be used to initiate the biogas reaction, which would otherwise be difficult without the use of the animal slurry or active liquor.

Figure 21: Image of cell being filled with fresh food processing waste

Figure 22: Image of fresh food processing waste in the digester cell

Figure 23: Image of partially digested waste in the cell

Municipal solid waste (MSW) has been introduced into a cell (see figure 24). The MSW contains a high portion of low activity organic waste and inactive waste streams as well as high activity putrescible organic substances. As the MSW is partially sorted (i.e. it does not contain glass or metal) and it has not been assessed to determine its composition, it is assumed that the composition is representative of the national average and approximately 30% of the original waste sample is active and can form biogas.

Figure 24: Image of cell containing MSW

Gas Composition range
CH_4 60% to 68%
CO_2 40% to 32%
H_2S <10ppm
H_2O 0%

Methane output varied from 0% at the start of the cycle to peaks of 80% for some feedstocks. There are five cells at different stages of digestion. The control system is set up so that the use of the biogas from all cells is maximized and the gases are blended to ensure a minimum methane concentration of 50% in the storage bag. Where several cells were in the high production phase of the cycle, the gas concentration of the turbine fuel could be between 60% and 70% although the composition tends to be between 60% and 65%. In most respects the digester is performing above expectations at present. This is probably due to the mode of operation. The solid residues remain in a single cell but the active liquor can be transferred from one cell to another to stimulate or improve the bioreaction. The operation is a hybrid of the batch and continuous processes. Also, the waste is remaining in a cell for longer than quoted in the literature. The complete reaction process is currently taking around 6 weeks with a biogas yield of 35 to 38 m^3/tonne, which is 52% greater than expected. The energy value varies during the cycle, as gases are blended even very low CV gases can be utilised. Biogas energy values of 32MJ/m^3 (gross) have been achieved with average gross values of 24 MJ/m^3 to 28 MJ/m^3. As there is some mixing of the liquid components it is unclear whether there is transfer water-soluble biodegradable components between cells and the effect this has on the net yield from the cell. This improved yield could also arise from the completion of the bioreaction in the cell and the increase in residence time as this reaction is not completed in the continuous reactor used elsewhere.

Turbine Operational Data

For the initial period after commissioning the turbine operated at full power (29kWe) for around 1 hour on each bag of fuel. Up to five runs per day could be achieved and a total of 68 starts (Total = 2240kWh). After this period it was decided to operate the turbine at 15kWe and 32 runs have been conducted at this power setting (Total = 1080kWh). Total operation on biogas during this trial is 146 hours by the end of October 2001. Gas consumption over this period is 2000m^3, which gives electrical efficiency of 26%.

15kWe is approximately equal to the site baseload and part load operation more than doubled the period of operation and significantly reduced the level of power exported. Trials on natural gas and biogas indicate that the efficiency remains stable across this part of the power range of the Capstone microturbine, which is achieved by controlling the turbine in a certain way. This mode of engine control is not used by all microturbine manufacturers and is not necessarily representative of the technology as a whole. The efficiency of most gas turbines would be expected to fall to an unacceptable low level at half load. Operating the turbine at part load and reducing the level of exported power increased the financial benefit of the system to the host site. Unless the exported and imported power values are equal, operation at or below the site load will be the preferred mode of operation. In the current trial, the power setting is fixed, however, the optimum set-up would be to link the output to the site requirements. This configuration and operational mode has been demonstrated on other trial sites.

As the fuel is blended from digester cells at different stages of the digestion process, the composition of the fuel changed on a regular basis. After commissioning, the gas in storage had stratified and there were several flameout shut downs caused by the increase in concentration of CO_2 in the fuel. Subsequent tests reduced showed a reduced number of flameouts, which is probably due to the reduction in the residence time of the fuel in storage. The turbine performed without problem in full and half load. Although it was perceived that combustion stability was improved during the operation at part load as there was less fluctuation in the combustion noise. Although the turbine flameouts were reduced during the latter full power tests, there was still some combustion instability. There are no monitored data to support whether this is true as the sampling rate is too low to capture rapid fluctuations in speed etc. however the improvements may be a consequence of the engine management system, or the improvement in gas quality. The full power trials were conducted prior to the part load tests and the gas quality has improved as the digestion process is continually being optimised. The improved quality of the electrical supply over that to the previous site has reduced the number of shutdowns due to grid irregularities. There have been some shutdowns where the ROCOF (rate of change of frequency) relay on the G59 connection panel has tripped. The ROCOF relay is present in order to provide protection when the grid fails. Only one ROCOF trip has occurred whilst the site was manned and it was not due to grid failure, as the rest of the site remained connected. As other trips occurred when the site was unmanned, the state of the grid during the trip is not known. The microturbine onboard diagnostics cannot be used once the unit has been disconnected from the utility by the ROCOF relay however they did not reveal any problems prior to disconnection. The cause of the trips is not known. They are unrelated to the prime mover technology and would affect all embedded generators in the same way.

Total operational time on biogas was 146hours with 3360kWh of electrical power produced of which 402kWh were exported from the site by the end of October 2001.

A heat recovery boiler was linked to the site hot water system this would have allowed 8700kWh of thermal energy to be recovered over the trial period. As the waste heat recovery unit was commissioned after the turbine, 6000kWh of heat has been recovered.

During the trial CO_2 emissions have been reduced by 320 kg.

At present, the low-grade heat in the exhaust and the carbon dioxide in the flue gas are not recovered, however, with a small modification to the exhaust system this could be achieved. The concept of carbon enrichment for horticulture has been demonstrated on other sites by Advantica using natural gas fuelled turbines. With appropriate modifications to the configuration and under ideal conditions, this site could generate annual CO_2 savings of 500 tonnes from the 30kWe cogeneration system.

Emissions

The exhaust flue gas emissions were as follows.

CO	41ppm to 76ppm
SO_2	0ppm
O_2	18.5%
NO	7ppm
NO_2	1ppm
C_XH_X	0.02% max
H_2S	5ppm
CO_2	2.49% to 2.62%

The CO and NOx figures indicate that the combustion can be optimized further. NOx emissions are higher than on the previous trial. Shorter run time (due to reduced storage volume) reduce optimisation iterations to 1 or 2 per run. The gas composition is more variable than in the previous tests. Variability of exhaust emissions confirms that the flue gas composition is a consequence of fuel composition.

Trial Comments

The trial ran very successfully during the trial period and the operation is continuing. The unit is currently operating for up to 11 hours per day at 15kWe.

The next stage is to reduce the emissions to allow the low grade heat and carbon dioxide to be recovered. This would increase the overall efficiency of the system from 71% to 84% which would further improve the financial performance of the system.

5. Techno-Economic Assessment

A preliminary techno-economic assessment can be carried out by extrapolating the trial data. Trial data are taken from tests where the cells are not operating in a fully commercial mode or at full capacity. Assumptions have been made to assess the potential financial performance of a commercial site. The site was designed as half of a 1000tonne digester, which would use a 5x2 array of digester cells. The techno-economic assessment is based around a full scale plant.

The trial data indicate that 9 batches of waste can be treated in each cell in 1 year. This equates to 9000tonnes of waste treated each year in a full scale 10 cell plant. Waste volume reductions of 90% have been achieved in the trial, which equates to 8100tonne waste reduction for a full scale plant. Gas production volumes from the completed trials were 35m^3 per tonne of waste. The annual gas production would equal 315,000 m^3. The current trial data indicate that the gross energy content is 25MJ/m^3 (net energy content is 23MJ/m^3). For a 30% efficient generator in a CHP system, outputs of 2kWh_e and 2.4kWh_t could be expected from 1m^3 of fuel. The current configuration produces 1.7kWh_e and 2.8kWh_t from 1$m^3$of fuel but the balance of heat available to heat required on site by the cells is has not been calculated at present. In the case of a 30% efficient generator 630MWh_e and 756MWh_t could be produced annually.

The financial benefit is greatest for a plant that is operated by a host site with sufficient waste for digester feedstock and large on site loads to utilise the heat and power. Several assumptions must be made in predicting the financial benefit of the plant. These assumptions are listed below.

The total investment cost is likely to be around £600k for the digester and CHP plant. Operation and maintenance costs are likely to be around £50k per annum. Gross savings from the plant would be equivalent to £283kper annum and net savings around £233k. This gives a simple payback period of 2.6 years.

Key assumptions

Waste disposal costs	£30/tonne	Electricity price	5p/kWh
Gas price	1p/kWh	Boiler efficiency	85%

Payback periods will fall as waste management costs increase driven mainly by the increase in landfill tax. The optimum processing time for each batch of waste is not yet clear. By reducing the processing period by 4 day, the revenue for the site will increase by 10%. If the processing cycle can be completed in 31 days, a payback period of 2years should be achievable. The above calculations do not take account of the emission reductions that are achieved as the system produces renewable energy. In an ideal site (linked to a greenhouse complex), emission reductions of 16tonnes of CO_2 per kWe are realistic. Long term, payback periods of less than 2 years are realistic.

6. Conclusions

The findings of this study can be summarised as follows:

a) A large market for distributed generation is likely

A wealth of commentary in the literature is overwhelmingly positive for the prospects of the emergence of a large market for small-scale power generation in the UK, Europe and US during the period to 2020. This broad base of expectation appears to be no mere hype – the factors driving this are strong and unlikely to evaporate. In particular, the environment is high on the political agenda and has resulted in national targets for the deployment of a range of renewable and natural gas-fuelled technologies. Some of these technologies are already starting to appear in the marketplace.

The size of this market is uncertain since it depends on a complex mix of political, economic and technological factors. However, by 2020 DG may account for 24GW, 171GW, and 261GW of generating capacity in the UK, Europe and US respectively.

b) A number of DG technologies can be fuelled with biogas

A number of current and emerging technologies would normally be fuelled with natural gas, but can also accept lower quality fuels. In particular, steam turbines, internal combustion engines, microturbines and Stirling engines accept biogas well. Fuel cells require much more stringent purification of the fuel, which adds further expense to the system.

c) *Significant quantities of DG technologies will be sold to biogas applications*

Driven largely by environmental factors, the development of the market for anaerobic digestion (e.g. from agricultural or process waste and sewage) and a greater exploitation of the landfill gas resource are expected. The attractiveness of many anaerobic digestion projects will depend on a complex economic case including capital costs, electricity savings and the sale of process by-products. Overall, economic environmental incentives will be needed to stimulate a large market.

Again, the market influences are such that predictions are necessarily uncertain. However, in the UK, installed capacity is estimated to grow to 1.1GW_e by 2020. This will be of the order of 1% of total generating capacity and 5% of distributed generation.

d) Microturbines will likely compete reasonably well with other technologies in small-scale biogas projects.

The benefits offered by the microturbine arise from its mode of operation. The fixed output, part load efficiency and low maintenance are the key benefits which improve operational effectiveness, however the reduced efficiency over piston engine may hinder market penetration.

e) The trial data indicate that biogas production can exceed predicted levels.

Biogas output from the digester has exceeded expectations in terms of both composition and volume. However the processing time is longer than suggested in the literature. The batch design for the digester is behind these main operational differences. Gas quality consistency must be improved further to improve operational effectiveness. Earlier indications suggest that biogas is sufficient to justify the use of cogeneration equipment.

f) The performance of the turbine.

Turbine performance has indicated that this is an ideal application for this equipment. The fixed output operation simplifies load management and the part load efficiency improves economic performance. The failures experienced during the trial were not caused by the use of biogas and are not unexpected when using prototype equipment. The microturbine has been demonstrated operating on gas mixtures with 50% methane without any difficulties. Gas clean up and processing is required which increases installation costs over natural gas systems. Although the microturbine is very tolerant to gas composition, ancillaries such as the compressor and dryer are not and must be protected.

g) Linkage to waste management.

The integrated waste to energy concept can be cost effective. In order to be economically attractive under current market conditions both the waste management and energy utilisation elements should be included. Applications where there is a waste management issue and large energy loads are likely to receive the greatest benefit from this system.

7. Recommendations

As the feedstock composition affects both composition and volume of gas produced and the rate of production, further tests on a variety of feedstocks under a range of process conditions should be carried out. Of particular interest should be wastes streams that are difficult to process by other means.

The process requires further optimisation in terms of both the digestion process and the gas processing and utilisation. The bio-reaction process is variable and not well understood, with further improvements are required to increase consistency. There is scope to improve the processing and storage of the fuel. The control and operation of the overall system can also be further optimised. The value and uses of the additional outputs, such as the solid residue, the water and the carbon dioxide enriched flue gases, must all be assessed as these have the potentially to broaden the applicability and improve the financial performance of an installation.

Once the optimized process is understood, an accurate techno-economic study can be undertaken. This study should be used to identify markets in which the concept would add significant financial benefit.

Plant scale is flexible with the current design, however the optimum size for the digester cell is not known. The impact of scale on cell performance and optimum plant size should both be determined.

When the performance of the system has been evaluated and optimised, the technology should be implemented. The initial stage of the implementation process should be trial demonstrations in the key market sectors, which are most likely to adopt the technology.

8. Acknowledgements

Advantica would like to acknowledge support from the DTI New and Renewable Energy Programme for completion of this work. We would also like to thank AMEC for allowing access to the IRW-EFR installation for the micro-turbine trial.

9. Information Sources

NB. Where information or documents are available online, web site addresses have been given in order to facilitate low-cost retrieval of documents and information. These addresses are correct at the time of writing, but are subject to change.

1. "Digest of United Kingdom Energy Statistics 2001", The Stationary Office, Norwich, 2001.
   http://www.dti.gov.uk/epa/digest01/contents01.htm

2. "2000 Annual Energy Review", European Union publication KO-BR-00-001-EN-C, January 2001.

3. "Renewable Energy Annual 2000", US Energy Information Administration report number DOE/EIA-0603(2000), March 2001.
   http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/rea.pdf

4. N.W. Lane and W.T. Beale, "Micro-Biomass Electric Power Generation", Third Biomass Conference of the Americas, Montreal, Quebec, Canada, August 1997.

5. S. Kartha, E.D. Larson, J.M. Ogden and R.H. Williams, "Biomass Integrated Gasifier/Fuel Cell Electric Power Generation and Cogeneration", 1994 Fuel Cell Seminar, San Diego, California, November-December 1994.

6. C.E. Trippel, J.L. Preston, J. Trocciola and R. Spiegel, "Operating a Fuel Cell Using Landfill Gas", 1996 Fuel Cell Seminar, Orlando, Florida, November 1996.

7. Y. Kishinevsky and S. Zeligher, "A 200kW ONSI Fuel Cell on Anaerobic Digester Gas", 1998 Fuel Cell Seminar, Palm springs, California, November 1998.

8. M. Takahashi and K. Wada, "FCPP Application to Utilise Anaerobic Digester Gas", 1998 Fuel Cell Seminar, Palm springs, California, November 1998.

9. L. Barchewitz and Jens Palsson, "Design of An SOFC System Combined to the Gasification of Biomass", Fourth European Solid Oxide Fuel Cell Forum, Lucerne, Switzerland, July 2000.

10. M.L. Ng, C.-L. Lin and Y.-T. Cheng, "Special considerations on Operating a Fuel Cell Power Plant Using Natural Gass with Marginal Heating Value", 1996 Fuel Cell Seminar, Orlando, Florida, November 1996.

11. J. Kivisaari, "Influence of Impurities in the Anode and Cathode Gases on Fuel Cell Performance and Life – A Literature Overview", 1994 Fuel Cell Seminar, San Diego, California, November-December 1994.

12. R.J. Spiegel, J.L. Preston, J.C. Trocciola and C.E. Trippel, "Fuel Cell Operation on Landfill Gas at the Penrose Power Station and the Groton Landfill", 1998 Fuel Cell Seminar, Palm springs, California, November 1998.

13. R. Steffen, O. Szolar and R. Braun, "Feedstocks for Anaerobic Digestion", Institute for Agrobiotechnology, Tulln University of Agricultural Sciences, Vienna, 1998. http://www.ad-nett.org/assets/images/Feednw1.pdf

14. M. Gustavsson, "Biogas Technology – Solution in Search of Its Problem", Dept. Interdisciplinary Studies, Goteborg University, March 2000. http://www.he.gu.se/dot/resources/biog_techn.pdf

15. Shakti Web site http://shakti.hypermart.net/biogas.html

16. "New and Renwewable Energy: Prospects in the UK for the 21st Century: Supporting Analysis", ETSU report R-122, 1999. http://www.dti.gov.uk/renew/condoc/support.pdf

17. Information from the Ontario Centre for Environmental Technology Advancement web site http://www.oceta.on.ca/profiles/apollo/scrubber.html

18. "The role of distributed Generation in Competitive Energy Markets", GRI, March 1999. http://www.gri.org/pub/solutions/dg/distgen.PDF

19. "Distributed Generation: Securing America's Future with Reliable, Flexible Power", National Energy Technology Laboratory, October 1999. http://www.fetc.doe.gov/products/power/ats/ref_shelf/distgen.pdf

20. Information from Ballard web site, 2001. http://www.ballard.com/viewpressrelease.asp?sPrID=212

21. Ballard Power systems Inc., Annual Report 2000. http://www.ballard.com/pdf/annual/Ballard-AR2000-full.pdf

22. Information from International Fuel Cells web site, 2001. http://www.ifc.com/commercial/pc25summary.pdf

23. J.D Leitman, "Global Carbonate Fuel Cell Activities and Visions", Fuel Cell 2000, Lucerne, Switzerland, July 2000.

24. P.Kraus, "The 250kW Direct Fuel Cell Cogenerator at Bielfield", Fuel Cell 2000, Lucerne, Switzerland, July 2000.

25. C.Bentley, M. Farooque, H. Maru and J. Leitman, “Direct Fuel Cell Commercialisation”
http://www.fce.com/dfc_comm.pdf

26. R.A. George, “Status of Tubular SOFC Field Unit Demonstrations”, Journal of Power Sources 86, 2000.

27. J. Sukkel, “Two Years Experience with the 100kW SOFC Cogeneration Unit at Arnhem”, Fourth European Solid Oxide Fuel Cell Forum, Lucerne, Switzerland, July 2000.

28. S.D. Vora, “Southern California Edison (SCE) 200kWe Pressurised SOFC Power System”, Fourth European Solid Oxide Fuel Cell Forum, Lucerne, Switzerland, July 2000.

29. Capstone Turbine Corporation, Annual Report 2000.
http://media.corporate-ir.net/media_files/NSD/cpst/reports/annualreport01.pdf

30. Capstone Micro Turbine Model 330 landfill gas/digester gas specification sheet
http://www.capstoneturbine.com/technology/specSheets/SpecSheetlandfill-digester.pdf

31. Los Angeles Department of Water and Power news release, August 2001
http://www.capstoneturbine.com/whatsnew/extrelease/lapwd081601.html

32. J.K. Steckel, “City Uses Microturbines to Generate Electricity from Biogas”, WaterWorld, January 2001.
http://ww.pennnet.com/Articles/Article_Display.cfm?&Section=Articles&SubSection=Display&ARTICLE_ID=90634&PUBLICATION_ID=41&VERSION_NUM=1

33. IT Group Inc news release, July 2001.
http://www.capstoneturbine.com/whatsnew/extrelease/itGroup196183.html

34. Honeywell press release, October 1999.
http://www.parallon75.com/press_releases/1999/oct04_99.html

35. Information from Mercury Electric Corporation web site, 2001.
http://www.mercuryelectric.com/reallifeapplications.html

36. N. Lenssen, “Distributed Generation: The Microturbine Market”, Electric Perspectives, July/August 2001.
http://www.eei.org/ep/editorial/Jul_01/0701generation.htm

37. “Developing Power systems for the 21st Century – Fuel Cell/ATS Hybrids”, National Energy Technology Laboratory.

http://www.fetc.doe.gov/products/power/ats/ref_shelf/hybrids.pdf

38. A.W. Layne, M. Williams, S. Samuelson and P. Hoffman, "Development Status of Hybrids", National Energy Technology Laboratory. http://www.fetc.doe.gov/products/power/ats/ref_shelf/hybrid.pdf

39. H. Ghezel-Ayagh, A.J. Leo and H. Maru, "Direct FuelCell/Turbine Hybrid System for Ultra High Efficiency Power Generation", FuelCell Energy web site, 2001. http://fce.com/dfc_turbine_hybrid.pdf

40. B. Elmegaard, B. Qvale, G. Carapelli and P. de Faveri Tron, "Open-cycle Indirectly fired Gas Turbine for Wet Biomass Fuels", Proceedings of the conference "ECOS 2001", Istanbul, Turkey, July 2001. http://www.et.dtu.dk/Halmfortet/publications/pdf/ecos01_open-cycle_indirectly.pdf

41. P. Lusk, "Methane Recovery from Animal Manures, the Current Opportunities Casebook", National Renewable Energy Laboratory report NREL/SR-580-25145, September 1998.

42. L. Nutting, "Technology Options for Using Landfill Gas", Second International Methane Mitigation Conference, Novosibirsk, Russia, June 2000. http://www.ergweb.com/methane/papers.html

43. "1999 Seven Year Statement for the Years 1999/00 to 2005/06", National Grid Company, 1999. http://www.nationalgrid.com/uk/library/documents/sys/mn_index.html

44. A. Despotakis, "Fuel Cells", SRI Consulting, 1999.

45. J. Gopal, J. Grau, P. Kulkarni and E. O'Neill, "Energy Commission Staff Distributed Energy Resources Training Seminar: Deployment/Case Studies/Agency Efforts", April 1999. http://foghorn.energy.ca.gov/distgen/documents/DEPLOYMENT.PDF

46. "Electricity Technology Roadmap, 1999 Summary and Synthesis", Electric Power Research Institute, July 1999. http://www.epri.com/corporate/discover_epri/roadmap/CI-112677-V1_all.pdf

47. E.J. Honiton, "Micro and Mini Turbine Technology", presented at the West Coast Energy Management Congress, June 2000. http://www.distributed-generation.com/Library/AEE_Presentation.pdf

48. "Distributed Utility Planning: An Introduction to Concepts and Issues", Vermont Department of Public Service.
http://www.state.vt.us/psd/ee/ee-DUP.htm

49. http://www.eren.doe.gov/distributedpower/pages/whatis_benefits.html

50. "Benefits of Distributed Power to Utilities", DPCA.
http://www.dpc.org/technologies.html

51. "Distributed Generation: System Interfaces", Arthur D. Little white paper, 1999.
http://www.arthurdlittle.com/dg/downloads/dg_sys_interface.pdf

52. Lord Marshall, "Economic Instruments and the Business Use of energy", November 1998.
http://www.hm-treasury.gov.uk/pub/html/prebudgetNov98/marshall.pdf

53. "Stability and Steady Growth for Britain", Pre-Budget Report, Cm 4479, November 1999.
http://www.hm-treasury.gov.uk/prebudget/Nov99/report/cm4479.htm

54. "Outline proposals for a UK Emissions Trading Scheme", CBI/ACBE Emissions Trading Group, September 2000.
http://www.weathervane.rff.org/refdocs/UKTrading11-99.doc

55. EU green paper on greenhouse gas emissions trading within the European Union, COM(2000)87, March 2000.
http://europa.eu.int/comm/environment/docum/0087_en.pdf

56. Seeboard, personal communication, August 2000.

57. "Increasing Levels of distributed Generation and Its Effect on Electricity Networks, ETSU K/EL/00176/REP, 1998.

58. R. Driver, "Embedded Generation – Realising the Potential for Network Benefits. Seminar 1: Contents and Outcomes", Econnect report, February 2000.

59. "Siting Committe Recommendation Regarding Distributed Generation Interconnection Rules", California Energy Commission Committee Report P700-00-004, May 2000.
http://foghorn.energy.ca.gov/reports/700-00-004.PDF

60. "Recommendation Regarding Distributed Generation Interconnection Rules", California Energy Commission Committee Report P700-00-006, June 2000.
http://foghorn.energy.ca.gov/reports/700-00-006.PDF

61. "Arizona State Draft Interconnection Requirements for Distributed Generation", November 1999.
http://159.87.17.5/meetings/minutes/isrev3.pdf

62. "1999 Interconnection Guidelines for Distributed Generation in Texas", Public Utility Commission of Texas, February 1999.
http://www.puc.state.tx.us/electric/projects/20363/guidlns.cfm

63. "Initial Comments by the Distributed Power Coalition of America", DPCA comments to regional transmission organisations rulemaking, December 1999.
http://www.dpc.org/publications/Rulemaking.html

64. Interconnect-2 proceedings, October 1998.
http://www.usfcc.com/Interconnect2Proceedings4.html

65. Interconnect-3 proceedings, October 1999.
http://www.usfcc.com/Interconnect2Proceedings4.html

66. T.R. Schneider, "Testimony on Interconnection of Distributed Resources", June 1999.
http://www.ieeeusa.org/FORUM/POLICY/1999/99june22.html

67. Summary List of Engineering Recommendations and Technical Specifications for Electrical and Engineering Business.
http://www.demon.co.uk/ea-esd/pubindex.html

68. "Consultative Document: Network Management Issues", DTI, November 1999.
http://www.dti.gov.uk/energy/egwg/condoc.pdf

69. R. Brent Alderfer, M. Monika Eldridge and T.J. Starrs, "Making Connections", National Renewable Energy Laboratory report, NREL/SR-200-28053, May 2000.
http://www.nrel.gov/docs/fy00osti/28053.pdf

70. "A Technical Guide to Connection of Embedded Generators to the Distribution Network", ETSU report, ETSU K/EL/00183/REP, 1999.

71. J. Mariyappan, "The Reducing Scale of Electricity: Impacts on the Environment, Infrastructure and Energy Markets", MPhil.1st year report, Imperial College of Science, Technology and Medicine, 1999.

72. "Review of Embedded Generation Issues", Association of Electricity Producers, July 1998.
http://www.aepuk.com/files/EMBGENPOLICY.doc

73. Energy Utilities Directorate Working Group on Network Issues for embedded Generation.
http://www.dti.gov.uk/energy/egwg/

74. "Distributed Generation: Understanding the Economics", Arthur D. Little white paper, 1999.
http://www.arthurdlittle.com/dg/downloads/dg_economics.pdf

75. W. Patterson, "Transforming Electricity", Earthscan Publications Ltd, London, 1999.

76. "Challenges of Electric Power Industry Restructuring for Fuel Suppliers", Energy Information Administration, September 1998.
http://www.eia.doe.gov/pub/electricity/chg_str_fuel.pdf

77. "The Changing Structure of the Electric Power Industry: Selected Issues 1998", Energy Information Administration Report, DOE/EIA-0562(98), July 1998.
http://www.eia.doe.gov/cneaf/electricity/chg_str_issu/chg_str_issu.pdf

78. "The Restructuring of the Electric Power Industry: A Capsule of Issues and Events", DOE/EIA-X037, January 2000.
http://www.eia.doe.gov/cneaf/electricity/chg_str/booklet/booklet.pdf

79. "Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity", December 1996.
http://www.europa.eu.int/eur-lex/en/lif/dat/1996/en_396L0092.html

80. "Directive 98/30/EC of the European Parliament and of the Council of 22 June 1998 concerning common rules for the internal market in natural gas", June 1998.
http://www.europa.eu.int/eur-lex/en/lif/dat/1998/en_398L0030.html

81. "Second Report from the Commission to the Council and the European Parliament on the State of Liberalisation of the Energy Markets", EU report COM(99)198, May 1999.
http://www.europa.eu.int/comm/energy/library/lib2ren.pdf

82. L. Goldstein, J. Mortensen and D. Trickett, "Grid-Connected Renewable-Electric Policies in the European Union", NREL/TP.620.26247, May 1999.
http://www.nrel.gov/docs/fy99osti/26247.pdf

83. "A Community Strategy to Promote Combined Heat and Power (CHP) and to Dismantle Barriers to its Development", October 1997.
http://www.eu-dhc.org/policy/CHP_target.html

84. http://www.oit.doe.gov/chpchallenge/chpchallenge.shtml

85. "Clean Energy for the 21st Century", Office of Energy Efficiency and Renewable Energy, DOE/GO-10099-911, December 1999. http://www.eren.doe.gov/cleanenergy/pdfs/CE21C-broch.pdf

86. "A Community Strategy to Promote Combined Heat and Power (CHP) and Dismantle Barriers to its Development", COM(97)514 Final, Commission Communication to the Council and the Parliament, May 1999. http://europa.eu.int/en/comm/dg17/514fi_en.htm

87. "Fueling the Future", technical report by Washington Policy and Analysis Inc, February 2000. http://www.fuelingthefuture.org/files/PDF_pages/FullReport.pdf

88. "Reliability of Natural Gas Power Generation Systems", GRI report GRI-93/0020, 1993. http://www.gri.org/pub/solutions/dg/reliability.pdf

89. R. McClelland, "First Commercial 200kW Fuel Cell Fleet: Experience, Lessons Learned and Future Perspective", 1994 Fuel Cell Seminar, San Diego, California, November 1994.

90. "1994-1998 Generating Unit Statistical Brochure", North American Electric Reliability Council", August 1999. http://www.nerc.com/~filez/gar.html

91. E-Wire Press Release http://ens.lycos.com/e-wire/August99/18aug9909.html

92. J. Fiorito, "ComEd Relies on Distributed Generation for Reliability", PMA Online, March 2000. www.retailenergy.com/articles/comed.htm

93. A.C. Khandkar, "Market Oriented Fuel Cell Product Development", Fourth European Solid Oxide Fuel Cell Forum: Proceedings Volume 2, Lucerne, Switzerland, July 2000.

94. http://www.intertechusa.com/energy/distributedpower2000/introduction.html

95. E Source Distributed Energy News, 21/7/00, July 2000.

96. "Supply Interruptions Following the Boxing Day Storms", May 1999. http://www.ofgem.gov.uk/elarch/documents/boxstorm.pdf

97. "Report on Distribution and Transmission System Performance 1998/99". January 2000.
http://www.ofgem.gov.uk/docs/datsjan.pdf

98. "The Social Effects of Energy Liberalisation", DTI, June 2000.
http://www.dti.gov.uk/energy/social3.pdf

99. "Quality of Supply: Attitudes of Business and Domestic Electricity Customers", research study conducted for OFFER by MORI, January - March 1999, May 1999.
http://www.ofgem.gov.uk/elarch/documents/moriqs.pdf

100. "Reliability Assessment 1999-2008", North American Electric Reliability Council, May 2000.
ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/99ras.pdf

101. "Office of Gas and Electricity Markets Plan and Budget April 2000 - March 2001", November 1999.
http://www.ofgem.gov.uk/elarch/documents/plan.pdf

102. A.H. Fuldner, "Upgrading Transmission Capacity for Wholesale Electric Power Trade"
http://www.eia.doe.gov/cneaf/pubs_html/feat_trans_capacity/w_sale.html

103. NORWEB, personal communication, August 2000.

104. D. Jeffers, "Electric and Magnetic Fields: The Facts", Electricity Association report.
http://www.electricity.org/uk_inds/environ/emf1.pdf

105. "Report of the Conference of the Parties on its Third Session, Held at Kyoto from 1 to 11 December 1997", March 1998
http://www.cop3.de/resource/docs/cop3/07a01.pdf

106. "Preparing for Implementation of the Kyoto Protocol", COM(1999)230, Commission Communication to the Council and the Parliament, May 1999.
http://europa.eu.int/comm/environment/docum/99230_en.pdf

107. "Climate Change: Draft UK Programme", March 2000.
http://www.environment.detr.gov.uk/climatechange/draft/index.htm

108. "Digest of United Kingdom Energy Statistics 1998", HMSO, London, 1998.

109. J. Herbert, "Putting Economic Power in Distributed Power", EIA presentation, October 1997.

http://www.eia.doe.gov/pub/oil_gas/natural_gas/presentations/1997/putting_economic_power_distributed_power/

110. Cogen Europe press release, March 2000.
http://cogen.org/pubfra5.html

111. PES licences.
http://www.ofgem.gov.uk/public/pgarc.htm

112. "Technical Requirements and Documentation for the Network Connection of Small-Scale Generation: As Applied to Embedded Generation in England and Wales", ETSU K/EL/00174/REP, April 1998.

113. D. Moskovitz, "Profits and Progress Through distributed Resources", February 2000.
http://www.rapmaine.org/P&pdr.htm

114. F. Escombe and A. Rawnsley, "Microturbines: Applications and Opportunities volume 2", EscoVale Consultancy Services report, October 1999.

115. British Biogen web site, 2001.
http://www.britishbiogen.co.uk

116. Practically Green web site, 2001.
http://www.practicallygreen.com

117. "Direct-Fired Biomass", from University of Missouri at Rolla web site, 2001.
http://www.ece.umr.edu/areas/power/biomass2.htm

118. A.H.H.M. Shomaker, A.A.M. Boerboom and A. Visser, "Anaerobic Digestion of Agro-Industrial Wastes:Information Networks, Technical summary on Gas Treatments", AD-NETT report H0489.A0/R002/TS/GR, August 2000.

119. "Biopower Program, Activities Overview", DOE/GO-102000-1049, June 2000.

120. "Small Modular Biopower Initiative USDOE Biopower Program", NREL presentation.

121. FuelCell Energy press release, August 2001.
http://www.fuelcellenergy.com/site/investor/press/releases/2001/08_16_01.html

122. B. Guzzone, "Landfill Gas Utilisation: The Future's So Bright", *MSW Management*, Vol 11, No 5, July/August 2001.
http://www.forester.net/mw_0107_gas.html

123. "Biosolids Generation, Use, and Disposal in the United States", Environmental Protection Agency report EPA530-R-99-009, September 1999. http://www.epa.gov/epaoswer/non-hw/compost/biosolid.pdf

124. G. Hartnell, "Promising Prospects for Landfill Gas", *New Review*, Issue 47, February 2001. http://www.dti.gov.uk/NewReview/nr47/html/landfill_gas.htm

125. "A centralised Thermophilic Biogas Plant in Denmark", CADDET technical brochure no. 43, 1996. http://www.caddet.co.uk/assets/no43.pdf

126. "Manure Digestion in a Poultry Farm in the Netherlands", CADDET technical brochure no 2, 1994. http://www.caddet.co.uk/assets/no2.pdf

127. A. Wellinger, "Process Design of Agricultural Digesters", Nova Energie, Ettenhausen, Switzerland, November 1999. http://www.ad-nett.org/AW_TS.pdf

128. "Energy for the Future: Renewable Sources of Energy", EC white paper, COM(97)599, November 1997. http://europa.eu.int/comm/energy/library/599fi_en.htm

129. "Campaign for Take-Off", Commission Services paper http://europa.eu.int/comm/energy/library/t-off-en.pdf

130. "The Renewables Obligation Preliminary Consultation", DTI document DTI/PUB 5052/4k/10/00/NP.URN00/1181, October 2000. http://www.dti.gov.uk/renew/ropc.pdf

131. "New and Renewable Energy: Prospects in the UK for the 21st Century", DTI document DTI/Pub 4024/3k/3/99/NP.URN 99/744, March 1999. http://www.dti.gov.uk/renew/condoc/energy.pdf

132. EU web site, 2001 http://europa.eu.int/comm/energy/en/pfs_altener_en.html

133. G. Hartnell, "Landfill Gas Looks Ahead", *New Review*, Issue 36, May 1998. http://www.dti.gov.uk/NewReview/nr36/html/inbusiness.html

134. B. Kohlstruck and R. Keitel, "Applications with Proton Exchange Membrane (PEM) Fuel Cells for a Deregulated Market Place", Fuel Cell 2000: Proceedings, Lucerne, July 2000.

135. http://images.cnn.com/NATURE/9906/30/fuel.cell.enn/index.html

136. Information from Allied Business Intelligence
http://alliedworld.com

137. "The Administrative Obstacles to the Development of Decentralised Cogeneration", COGEN Europe Market Report, November 1999.

138. UK Generation Projects", Electricity Association, May 2000.
http://www.electricity.org.uk/inds_fr.html

139. "Distributed Generation -- an Overview", PWI Energy white paper, November 1998.
http://www.pwi-energy.com/main/whitepapers/Distributed%20Generation.htm

140. "Natural Gas-Fueled Reciprocating Engines Fastest Growing Prime Movers for Distributed Generation – Part 1", April 2000.
http://www.aga.org/Publications/GasTechnology/Spring2000/Articles/2472.html

141. "Renewable Energy 2000: Issues and Trends", Energy Information Administration report DOE/EIA-0628(2000), February 2001.
http://tonto.eia.doe.gov/FTPROOT/renewables/06282000.pdf

142. "Opportunities for Micropower and Fuel Cell/Gas Turbine Hybrid Systems in Industrial Applications, Volume 1", Arthur D Little report 38410, January 2000.

143. "US Methane Emissions 1990-2020: Inventories, Projects and Opportunities for Reductions", United States Environmental Protection Agency report EPA 430-R-99-013, September 1999.
http://www.epa.gov/globalwarming/publications/emissions/methane_emissions.pdf

144. "New and Renewable Energy: Prospects in the UK for the 21st Century, Conclusions in Response to the Public Consultation", Department of Trade and Industry document DTI/Pub 4649/9k/1/00/NP.URN 00/590, January 2000.
http://www.dti.gov.uk/renew/condoc/policy.pdf

145. J. Bluestein, "Status and Potential of U.S. CHP", First International Symposium on Combined Heat and Power, Washington DC, February 2000.
http://www.eren.doe.gov/der/chp/pdfs/bluestein.pdf

146. W.E. Liss, "Natural Gas Power Systems for the Distributed Generation Market", GRI Technical Paper, GRI-99/0198, November 1999.
http://www.gri.org/pub/solutions/dg/pgen99.PDF

147. "Renewable Energy annual 1999: With Data for 1998", Energy Information Administration report, DOE/EIA-0603(99), March 2000.
http://www.eia.doe.gov/cneaf/solar.renewables/rea_data99/rea.pdf

148. K. Davidson. "Combined Heat and Power Energy Solutions for the 21st Century", First International Symposium on Combined Heat and Power, Washington DC, February 2000.
http://www.eren.doe.gov/der/chp/pdfs/davidson.pdf

149. Office of Energy Efficiency and Renewable Energy Strategic Plan, DOE/GO-102000-0956, March 2000.
http://www.eren.doe.gov/overview/eerestrategicplan.pdf

150. "Batch Anaerobic Digestion of Green Waste in a BIOCEL Converter", CADDET technical brochure no 134, 2000.
http://www.caddet.co.uk/assets/no134.pdf

151. "Effective Treatment and Recycling of Livestock Waste", CADDET technical brochure no 150, March 2001.
http://www.caddet.co.uk/assets/no150.pdf

152. "Biogas Combined Heat and Power in Sweden", CADDET technical brochure no 112, 2000.
http://www.caddet.co.uk/assets/no112.pdf

153. Parallon75 specification sheet, Honeywell web site, 2001.
http://www.parallon75.com/quickspec.html

154. R. Boyd, "Internalising Environmental Benefits of Anaerobic Digestion of Pig Slurry in Norfolk", University of East Anglia, 2000.
http://www.roseworthy.adelaide.edu.au/~pharris/biogas/pigad.pdf

155. R. Klinger, "Environmental Aspects of Biogas Technology", German Biogas Association, 1999.
http://www.ad-nett.org/TS-ENV.pdf

156. I. Higham, "Status of Anaerobic Digestion for Agricultural Wastes in the UK", April 1997.
http://www.ad-nett.org/html/body_uk.htm

157. E. Colleran, "Hygenic and Sanitation Requirements in Biogas Plants Treating Animal Manures or Mixtures of Manures and Other Organic Wastes", Environmental Research Unit, Department of Microbiology, National University of Ireland, 1999.
http://www.ad-nett.org/pathogens.pdf

158. Technical summary by Working Group I of the Intergovernmental Panel on Climate Change, 2001.
http://www.ipcc.ch/pub/wg1TARtechsum.pdf

159. "Energy and Anaerobic Digestion", Biogas Works web site, 2001.
http://www.biogaswrks.com/Index/Energy%20&%20AD.htm

160. "Environment and Anaerobic Digestion", Biogas Works web site, 2001.
http://www.biogasworks.com/Index/Environment%20&%20AD.htm

161. "Profiles of Leading Renewable Energy Technologies for the Massachusetts Renewable Energy Trust fund", Arthur D Little report 37820, October 1998.

162. "Odour, Pathogens and Anaerobic Digestion", Biogas Works web site, 2001.
http://www.biogasworks.com/Index/Odor,%20Pathogens%20&%20AD.htm

163. "Follow the Methane", Biogas Works web site, 2001.
http://www.biogasworks.com/Index/Follow%20the%20Methane.htm

164. A. Nordberg, "Legislation in Different European Countries Regarding Implementation of Anaerobic Digestion", Swedish Institute for Agricultural Engineering, 1999.
http://www.ad-nett.org/TS_leg.pdf

165. P. Wheeler, "Commercial and Strategic Perspectives for Anaerobic Digestion", International Directory of Solid Waste Management 2000-2001.
http://www.jxj.com/yearbook/iswa/2000/anaerobic_digestion.html

166. "An Analysis of Landfill Gas Monitoring Well Design & Construction", Missouri Department of Natural Resources web site, 2001.
http://www.dnr.state.mo.us/deq/swmp/fgtask3a.htm

167. "Landfill Guidelines, Hazards of Burning at Landfills", Ministry for the Environment, Wellington, New Zealand, December 1997.
http://www.mfe.govt.nz/about/publications/waste/landfillburn.pdf

168. Information from AD-NETT web site database, 2001.
http://www.ad-nett.org/html/databases.html

169. S. Masemore and S. Piccot, "Electric Power Generation Using a Phosphoric Acid Fuel Cell on a Municipal Solid Waste Landfill Gas Stream", Greenhouse Gas Technology Centre report EPA-VS-GHG-01, August 1998.
http://www.sri-rtp.com/Verification%20Info/fuelcells.pdf

170. "The Landfill Tax Regulations 1996", The Stationery Office Limited, 1996.
http://www.hmso.gov.uk/si/si1996/Uksi_19961527_en_1.htm

171. “Council Directive 1999/31/EC of 26 April 1999 on the Landfill of Waste”, April 1999.
http://europa.eu.int/eur-lex/en/lif/dat/1999/en_399L0031.html

172. Frank Escombe, EscoVale Consultancy Services, private communication, June 1999.

173. Frank Escombe, “Fuel Cells: Applications and Opportunities volume 2”, EscoVale Consultancy Services report, September 1994.

174. “A Matrix for Distributed Energy Resource Technologies”, PMA Online.
http://www.retailenergy.com/articles/Distributed%20Resource%20Matrix.pdf

175. F. Escombe and A. Rawnsley, “Microturbines: Applications and Opportunities volume 1”, EscoVale Consultancy Services report, August 1999.

176. Paul Holtberg, “Electricity and Natural Gas: Partners or Adversaries?”, Presented to OIPA Annual Meeting, Afton, OK, June 2000.

177. “Distributed Generation Market Outlook”, Gas Research Institute web site, 2000.
http://www.gri.org/pub/solutions/dg/outlook.html

178. Consumer Energy Council of America web site, 2000.
http://www.cecarf.org/domedist.html

179. DeMontfort University web site, 2001.
http://www.dmu.ac.uk/ln/itc

180. AMEC web site, 2001.
http://www.amec.com/news/issue_2_2001/wastenot...wantn.html